EXHIBIT 1

NEPR

Received:

Aug 30, 2022

6:31 PM

COMMONWEALTH OF PUERTO RICO
PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU

IN RE: RESOURCE ADEQUACY STUDY	**CASE NO.:** SUBJECT: Filing of Resource Adequacy Study prepared by LUMA

MOTION TO SUBMIT LUMA'S RESOURCE ADEQUACY STUDY

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COME NOW LUMA Energy, LLC and **LUMA Energy ServCo, LLC** (jointly referred to as "LUMA"), and, through the undersigned legal counsel, respectfully submits LUMA's Resource Adequacy Study:

I. Introduction

1. On June 1, 2021, LUMA commenced operating the Puerto Rico Transmission and Distribution System ("T&D System") pursuant to the Puerto Rico Transmission and Distribution System Operation and Maintenance Agreement by and among LUMA, the Puerto Rico Electric Power Authority ("PREPA") and the Puerto Rico Public-Private Partnerships Authority dated as of June 22, 2020 (the "T&D OMA").

2. In accordance with the T&D OMA, LUMA is required to "maintain Resource Adequacy that may require new generation procurement for Generation Projects[1] or Generation

[1] "Generation Projects" are "any and all projects or transactions with respect to any function, service or facility of [PREPA] related to the generation of Power and Electricity, including the repair, replacement, improvement, sale, removal and retirement, alteration and addition of any generation asset, and in respect of which [PREPA] or the Government of Puerto Rico may enter into a Partnership Contract (as defined in Act 29-2009[, as amended])." T&D OMA at Section 1.1, page 17.

Supply Contracts[2], which procurement shall be done in accordance with the Integrated Resource Plan and Applicable Law." *See Id.* at Section 5.13(d). With respect to any such procurement, LUMA is required to:

> (i) **prepare risk assessments and analyses in support of Resource Adequacy** and Generation Project or Generation Supply Contract procurement prioritization and planning, which shall take into account the Integrated Resource Plan and Applicable Law (and which assessments and analyses PREB may request from time to time);
> (ii) prepare long and short-range transmission and distribution planning analyses and forecasts to determine the need for Generation Project or Generation Supply Contract procurement which shall take into account the Integrated Resource Plan to the extent applicable (and which analyses and forecasts PREB may request from time to time);
> (iii) **meet with PREB on an annual basis to review and assess the prepared analyses, demand projections** (prepared in accordance with the Integrated Resource Plan), **existing System Power Supply[3], Legacy Generation Assets[4] and generation assets owned by [independent power producers] related to the supply of Power and Electricity[5], and determine whether additional power supply sources are needed**; […]
> […]

Id. (Emphasis added.)

II. Submission of Resource Adequacy Study

4. As per LUMA's role and associated functions, and in attention to the requirements of Section 5.13(d) of the T&D OMA, LUMA has prepared a study containing risk assessments

[2] "Generation Supply Contracts" is defined as "any contract between [PREPA] and an [independent power producer] relating to the sale and purchase of Power and Electricity including power purchase agreements". *Id*.

[3] The term "System Power Supply" refers to "electric capacity, energy and ancillary services from any power supply sources authorized under Applicable Law to operate in the Commonwealth". *Id*. at Section 1.1, page 30.

[4] "Legacy Generation Assets" means "any power plants and any facilities, equipment and other assets related to the generation of Power and Electricity existing as of the date [of the T&D OMA] and in which [PREPA] or GenCo has an ownership or leasehold interest". *Id.* at Section 1.1, page 19. "GenCo" means "the entity, which may be directly or indirectly owned by [PREPA or an affiliate of PREPA], that acquires or obtains ownership of the Legacy Generation Assets after the reorganization of PREPA". *Id*. at Section 1.1, page 16.

[5] "Power and Electricity" means "the electrical energy, capacity and ancillary services available from the System Power Supply." *Id*. at Section 1.1, page 25.

and analyses in support of Resource Adequacy for Fiscal Year 2023, which spans from July 1, 2022 to June 30, 2023. The report is attached as *Exhibit 1* herein, titled "Generation Resource Adequacy Analysis" dated June 30, 2022 ("Resource Adequacy Study"). LUMA plans to submit a Resource Adequacy Study to the Energy Bureau at least annually.

5. The Resource Adequacy Study was developed to inform strategic resource planning decisions for the Puerto Rico electric system and includes an assessment on electricity generation sufficiency needs by evaluating the risk of insufficient electric supply to meet demand. *See Exhibit 1*, Executive Summary. In assessing the Puerto Rico electric system resource adequacy LUMA looked at certain guidance based on current utility industry practice in North America, including standards approved by the Federal Energy Regulatory Commission (FERC) or established by the National American Electric Reliability Corporation (NERC). *See id*. at pages 17 and 40.[6]

6. The Resource Adequacy Study is an important tool to help make decisions regarding generation retirements, additions, modifications, maintenance schedules, and other items to reduce the risk of insufficient electric supply. *See id*. at Executive Summary and Section 1.0. Specific recommendations on generation capacity addition and the analyses to determine which technologies are best suited to meet system needs are outside the scope of the Resource Adequacy Study. The Resource Adequacy Study is a critical input to the analyses done as part of the Integrated Resource Plan ("IRP") process. *See id*.

III. Relevant Statutory Framework

7. Act 57-2014 gives the Energy Bureau authority to oversee the quality, efficiency and reliability of electric power services provided by electric power companies certified in Puerto

[6] Although LUMA is not regulated by these entities, it references their guidelines when possible and consistent with the applicable laws and regulations as they provide a valuable framework and methodology in connection with the preparation of an analysis such as the Resource Adequacy Study.

Rico, to guarantee a robust grid that serves the needs of the island. *See id*. at Section 6.3(d), 22 L.P.R.A. §1054b. Furthermore, this Energy Bureau has authority to "review and approve the optimum energy reserve margin needed for Puerto Rico and ensure compliance therewith." *Id.* at Section 6.3(dd).

IV. Request to Open a New Non-Adjudicative Proceeding

8. LUMA respectfully requests that this Energy Bureau open a new non-adjudicative proceeding to discuss the Resource Adequacy Study that is submitted as *Exhibit 1* to this Motion. Although the Resource Adequacy Study is associated with a specific requirement of the T&D OMA, it will inform the upcoming IRP process and is geared at informing current planning and decision-making that will take place before the next IRP is approved. The Resource Adequacy Study will also directly inform other proceedings currently before the Energy Bureau's consideration such as the following: Case No. NEPR-MI-2021-0013, *In re: Despliegue de Infraestructura de Cargadores para Vehículos Eléctricos*; Case No. NEPR-MI-2021-0009, *In Re: Puerto Rico Test for Demand Response and Energy Efficiency*; NEPR-MI-2022-0001, *Energy Efficiency and Demand Response Transition Period Plan*; NEPR-AP-2018-0004, *In Re: The Unbundling of the Assets of the Puerto Rico Electric Power Authority*. Given the importance of the Resource Adequacy Study for the aforementioned proceedings and potentially others, as well as for the IRP, LUMA respectfully submits that a new regulatory proceeding is appropriate and will better enable an integrated consideration of this study. LUMA welcomes the opportunity to participate in and present the Resource Adequacy Study in a technical workshop or conference.

9. LUMA remains committed to working with the Energy Bureau, generators, and other stakeholders to address the systemic generation issues identified in the Resource Adequacy Study to provide the people of Puerto Rico with safe, reliable, and clean energy.

WHEREFORE, LUMA respectfully requests that the Energy Bureau **receive** the Resource Adequacy Study included as *Exhibit 1* to this Motion and open a new non-adjudicative proceeding to discuss the Resource Adequacy Study.

RESPECTFULLY SUBMITTED.

In San Juan, Puerto Rico, this 30th day of August 2022.

We hereby certify that we filed this Motion using the electronic filing system of this Energy Bureau and that we will send an electronic copy of this **motion to the attorneys for PREPA**, Joannely Marrero-Cruz, jmarrero@diazvaz.law; and Katiuska Bolaños-Lugo, kbolanos@diazvaz.law.

DLA PIPER

DLA Piper (Puerto Rico) LLC
500 Calle de la Tanca, Suite 401
San Juan, PR 00901-1969
Tel. 787-945-9107
Fax 939-697-6147

/s/ Margarita Mercado Echegaray
Margarita Mercado Echegaray
RUA NÚM. 16,266
margarita.mercado@us.dlapiper.com

/s/ Laura T. Rozas
Laura T. Rozas
RUA Núm. 10,398
Laura.rozas@us.dlapiper.com

Exhibit 1

Resource Adequacy Study

LUMA

Generation Resource Adequacy Analysis

August 30, 2022

Contents

Appendices

Figures and Tables

Acronyms and Abbreviations

Acronym/Abbreviation	Definition/Clarification
BESS	battery energy storage system
BTM	behind the meter
ERM	energy reserve margin
FY2023	fiscal year 2023
HECO	Hawaiian Electric Company
IRP	Integrated Resource Plan
LOLE	loss of load expectation
LOLH	loss of load hours
LOLP	loss of load probability
LUMA	LUMA Energy [also, the “System Operator”]
MW	megawatt
MWh	megawatt hour
NERC	North American Electric Reliability Corporation
PRAS	Probabilistic Resource Adequacy Simulation
PREB	Puerto Rico Energy Bureau
PREPA	Puerto Rico Electric Power Authority
PRM	planning reserve margin
PV	photovoltaic
System Operator	LUMA Energy [also, “LUMA”]
VIWAPA	Virgin Islands Water and Power Authority
Acronyms & Abbreviations Appearing in Appendices Only	
ELCC	effective load carrying capability
EUE	expected unserved energy
FRCC	Florida Reliability Coordinating Council

Executive Summary

This report assesses the sufficiency of electricity generation owned and operated by the Puerto Rico Electric Power Authority (PREPA) and other generators to meet existing electric customer load requirements in Puerto Rico by evaluating the risk of loss of load during the 12 months beginning on July 1, 2022, or Fiscal Year (FY) 2023. LUMA, which does not generate electricity, carried out this analysis in compliance with its responsibilities under the T&D OMA to inform the Puerto Rico Energy Bureau (PREB), policymakers and stakeholders about the adequacy and inadequacy of generation resources in the Puerto Rico electric system and to inform strategic resource planning decisions.

The importance of this analysis of the generation adequacy can't be overstated as it speaks directly to expected stability and reliability of Puerto Rico's energy system, and its generators, to meet expected demand. Among the key findings of this historic resource adequacy analysis include the following:

- Using electric utility industry standards for measuring resource adequacy, Puerto Rico has inadequate supply resources to deliver reasonable system reliability. Meaning there is not reliable generation capacity by PREPA and other generators to meet expected demand, thereby raising the risk of load shedding outages beyond industry standards.
- The output of this report is a statistical analysis of how many days there is a probability of not enough generation capacity being produced by PREPA and the other generators to meet customer demand. Note that the results do not forecast what will actually occur with respect to resource adequacy in FY2023, they are instead a statistical probability of different scenarios; however, the figure does help to quantify the risk,
- The loss of load expectation (LOLE) for Puerto Rico for FY2023 was calculated to be 8.81 days per year. Meaning that on average it is expected that there will be 8.81 days per year when customer demand will not be fully served by PREPA and other generators in FY2023. This measure is 88 times higher than the utility industry benchmark of 1 day in 10 years LOLE standard (0.10 days per year).
- For reference, the most likely outcome for a system that can meet the utility industry target standard of a 0.1 days per year LOLE (when load is greater than generation capacity) would be *less* than zero days in any given year. The study indicates that in Puerto Rico there is a high probability of *much greater* than zero days per year LOLE.
- Overall, issues with lack of sufficient energy generation raise the risk of outages for the customers and communities that LUMA serves every day.

The resource adequacy analysis also highlights the risk of load shedding outages is not the result of lack of enough generation capacity. In fact, if fully operable, there is a substantial amount of nameplate generation capacity installed in Puerto Rico. However, most of PREPA's generation is unreliable and too frequently incapable of operating when electricity is needed to meet the energy needs of Puerto Rico due to the age and maintenance history of the generation plants. The principal causes of PREPA's lack of sufficient generation include the following:

- **Prolonged planned maintenance**: PREPA's power plants often take long durations for execution of planned repair activities. Whenever a power plant is on a planned maintenance outage, it is unable to generate electricity. For example, Costa Sur Unit 6 was in outage for four months at the end of 2021, Costa Sur 5 will be out at the end of 2022 for four months, and San Juan Unit 5 was in outage for six months starting at the beginning of 2022. What makes planned outages even more impactful is that the actual outages themselves then have an average delay of 20%. The net result is PREPA peaker and baseload plants spend far in excess of average time in planned outage periods compared to industry.
- **High forced outage rates:** Forced outage rates for PREPA's existing power plants are generally very high, meaning the power plants break down frequently and are not available to meet energy demand. When different power plants happen to break down at the same time, there is significant risk that there will not be enough remaining generation available to cover the load. In PREPA's historical record both the frequency and duration of forced outages are considerably higher than industry average for comparable plants. PREPA's baseload plants (the larger, less expensive units) have a historic forced outage rate of approximately 11% and the older peaker plants average 31% while AES has 3% and EcoElectrica 2%.
- **Partial plant deratings:** The issue of partial plant deratings represent limitations that the generator imposes on the capacity that a plant can provide when called upon. Plant derates occur most days in Puerto Rico, and last from a few days to longer term (weeks, months, or effectively permanent). For example, relatively simple modifications to come into compliance with EPA air emissions requirements for the three newest units on the system—the three simple cycle turbines totaling 81 MW located at Palo Seco—have been ongoing for over 12 months, depriving the system of peaking capacity and black start units critical to restoring service after blackouts.

Impact of the unreliability & unavailability of PREPA Generation Facilities

The impact of insufficient generation is significant given the fact that Puerto Rico's is both **unable to import electricity from neighbors and the generation portfolio is "lumpy" and dominated by a concentration of large units that generate electricity**. For example, the loss of a single large power plant due to a forced outage immediately can reduce the total available generating capacity by roughly 10%. The cascading impact of such loss of generation capacity puts added demand on other generation facilities - many of which are often already being fully utilized. Given the unreliable nature of PREPA's generation facilities, the study included a scenario assuming the loss of a single large generator for an extended period. The conclusion of that scenario is that the loss of a single large generator would likely result in extended outages caused by insufficient generation supply to meet energy demand.

The results, for example, indicate that the timing of the **largest resource deficiency is during the evening hours -** with approximately 55% of LOLH occurring during the four hours between 7 p.m. and 11 p.m. **Summer months are the most challenging** in terms of loss of load. The reason for this is primarily system load driven: the highest system load, meaning the demand for energy, occurs in the summer months when it is hot, and residents use more air conditioning. As a result, the lack of sufficient generation from PREPA and other generators can directly endanger the stability and reliability of the energy system increasing the likelihood for load shedding outages.

Looking Ahead: Minimizing the Risk of Generation Outages

Looking ahead, the people of Puerto Rico remain critically dependent on the performance of PREPA's and the other independent generation plants to meet expected customer demand. LUMA, as the T&D operator, has limited ability to control the negative impact that the specific lack of generation has on the reliability of the energy system. Put simply, LUMA can't deliver the energy to meet customer demand unless PREPA and other generators generate enough energy.

This resource adequacy analysis provides measures of the high risk of insufficient generation relative to demand. Improving resource adequacy in order to reduce the risk of "load shedding" outages that are the result of lack of generation requires further discussion and review involving the Energy Bureau, generators, policymakers, LUMA and key stakeholders. Key issues that will help inform this discussion are summarized below.

- It is critical that PREPA achieve a minimum 65% generation plant availability that it has committed to in numerous PREB hearings and public venues to ensure there exists sufficient resource adequacy to meet forecasted energy demand.

- To support the 65% availability target above, it is critical that PREPA achieve close to benchmark for planned outages durations. The first step would be improved outage planning and execution, as there is no excuse for 20% average delay when the industry experiences outage delays of less than 5%.

- PREPA obtaining EPA permits or waivers to operate already-installed generation units that are currently limited by permit issues could potentially reduce the large number of derates in PREPA's generation fleet.

- Based on the current forecast, the addition of dependable bulk supply resources is required to reduce the risks of shortfalls. In the short term, an emergency installation of temporary units could be added. The scale of the mitigation would depend on the size and timing of installation of these resources.

- Emergency installation of new renewable, biofueled reciprocating engine or combustion turbine technology could provide added capacity and contribute to RPS targets.

- LUMA is working with stakeholders in order to have a coordinated effort that emphasizes several demand side mitigation efforts including demand response program, increased consumer outreach related to energy efficiency, and voluntary conservation efforts.

- All parties, including LUMA, PREB, and P3A, should work together to encourage and promote the adoption of additional distributed energy resources (i.e., renewables) that can provide some additional system support. While the immediate impact of such distributed energy resources may be limited over the coming year, it represents a critical aspect to Puerto Rico's energy future.

Roles & Responsibilities

The legal framework for the electric sector established by Act 17-2019 and other laws establish clear roles for different participants in the electric sector, including the division of generation (PREPA) from transmission and distribution (LUMA) activities. Generators, including PREPA and independent producers like AES and Ecoelectrica, are responsible for operation and maintenance of their facilities, while LUMA is responsible for the operation of the transmission and distribution system as well as overall system coordination, planning and analyses.

Under the Puerto Rico Transmission and Distribution Operation and Maintenance Agreement between the Puerto Rico Electric Power Authority (PREPA), the Public Private Partnerships Authority (P3 Authority), LUMA Energy, LLC and LUMA Energy ServCo (collectively, LUMA) effective June 21, 2020 (T&D OMA), LUMA carries out multiple activities in order to improve the energy reliability and grid resilience of the Puerto Rico electric sector. Among these are planning and conducting other studies to assess the risks of resource adequacy for the electric system to meet the energy demands of Puerto Rico. LUMA is also the system operator for Puerto Rico and carefully monitors and dispatches available generation resources—operated by PREPA, Ecoeléctrica, AES Puerto Rico and others—to meet customer demand.

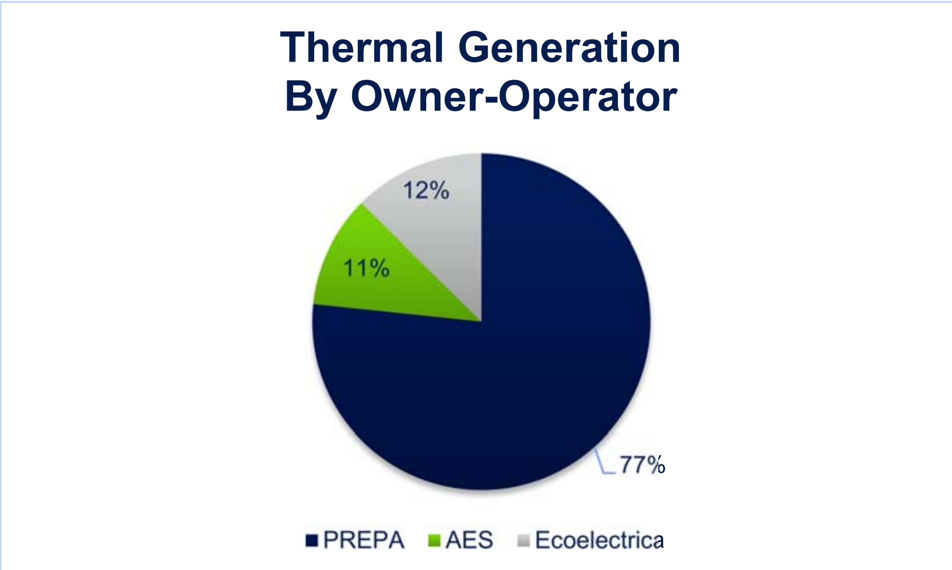
To be clear, LUMA does not own or operate any generation facilities. LUMA carries out plans and analyses, and coordination. Generators, PREPA and others are responsible for the maintenance and upkeep of their generation facilities, and ultimately for the availability and performance of their units. The relatively low availability and poor performance of PREPA's generation fleet is the principal cause for Puerto Rico's low resource adequacy.

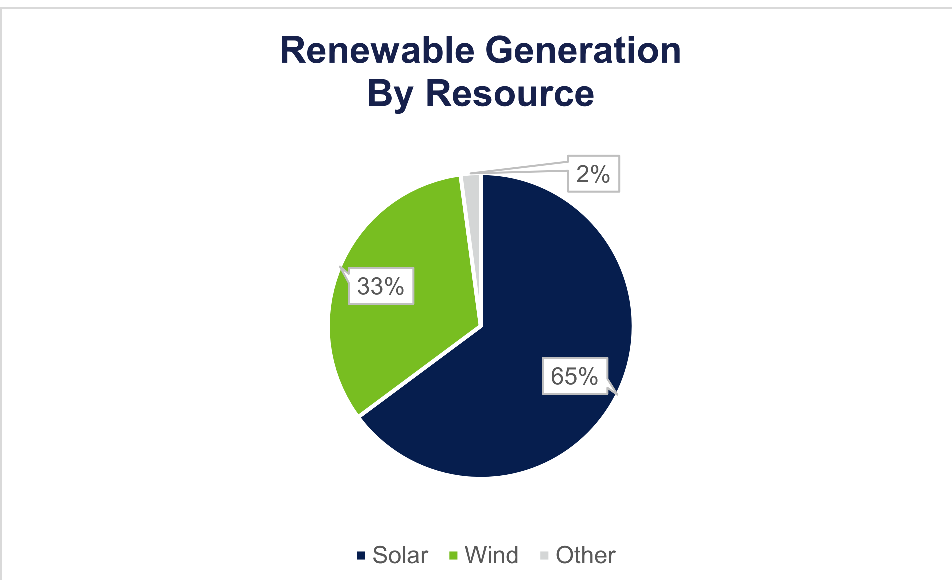
Given the persistent confusion over the structure of the energy system, and specific areas of responsibilities, it is important to stress that LUMA cannot control the reliability impact or risk of outages that are the direct result of generator performance (when generators are unable to produce enough energy to meet expected demand. The following tables and charts outline specifically the generator roles and responsibilities, and Puerto Rico's generation capacity.

Generation Roles and Areas of Responsibility

PREPA	IPP Generators	LUMA	PREB
Responsible for supply, production and efficiency of 77% of Puerto Rico thermal Generation	Responsible for supply, production and efficiency of 23% of Puerto Rico thermal Generation	Responsible for monitoring and delivering available generation produced by PREPA and other generators. Overall planning for the system.	Responsible for oversight of the electricity sector, regulation of activities, setting tariffs and approving plans.

Puerto Rico Generation Capacity





Report Scope and Methodology

At a high level, resource adequacy analyses quantify the risk that an electrical system is unable to serve system load because of insufficient generation capacity. Electrical system resource adequacy guidelines are based on regulatory requirements, system operator policies, and utility practice including policies set by the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), state/territory governments, and regional regulating authorities. Standards for resource adequacy across the industry are based on the needs of the specific utility.

The methodology followed for assessing the Puerto Rican electric system resource adequacy as discussed in this report is consistent with guidance provided by both mainland United States regulators and electric planning regions. This report supports decision-making regarding generation retirements, additions, modifications, maintenance schedules, and other items to reduce the risk of insufficient electric supply. Specific recommendations on new generation capacity additions would typically be made after analyses to determine which technologies are best suited to meet system needs and are the subject of the Integrated Resource Planning (IRP) process. The Energy Bureau approved a Modified Action Plan in August 2020 based on the IRP carried out by PREPA. This report provides critical inputs into the next IRP being prepared by LUMA as well as processes and discussions overseen by the Energy Board which will help drive how Puerto Rico can reduce the risk of insufficient supply to meet energy demand. LUMA is committed to working with government, generators, and the regulator to address these systemic generation issues to provide the people of Puerto Rico with safe, reliable, and clean energy.

Resource adequacy simulations for Puerto Rico are focused on FY2023. This 12-month time period from July 1, 2022, to June 30, 2023 was simulated on an hourly basis to calculate if there is sufficient available generation capacity to meet load for each hour of each day. FY2023 was simulated many times, with each iteration considering forced outages and other scenarios occurring randomly at different times based on a Monte Carlo simulation. The forced outage rates considered for this analysis are based on historical forced outage data. The output of the analysis is a statistical distribution of simulation results that provide an estimate of the risk associated with the potential of generation shortfalls.

The simulations considered electrical contributions from both thermal generators and renewable generators. Inputs into the simulations, such as generator available capacity, forced outage rates, renewable generation, and similar items, are based on historical operating data for the generators.

This analysis utilized LUMA's most recent annual load forecast of expected demand. The projection is done for each month based upon the coming period's expected weather, economic activity, and other macro-economic factors. The macro-economic factors are consistent with projections utilized for Puerto Rico's fiscal planning process for FY2023. The projection of demand also takes into account residential solar as a net demand reduction.

It should be noted that demand has been forecasted based on average historical temperatures. Higher-than-average temperatures would be expected to lead to higher peak demand, reduced reserve margins and a higher risk of insufficient generation to meet system load.

The focus time horizon for this analysis was fiscal year 2023 (FY2023), which spans from July 1, 2022, to June 30, 2023.

Calculation Results and Implications

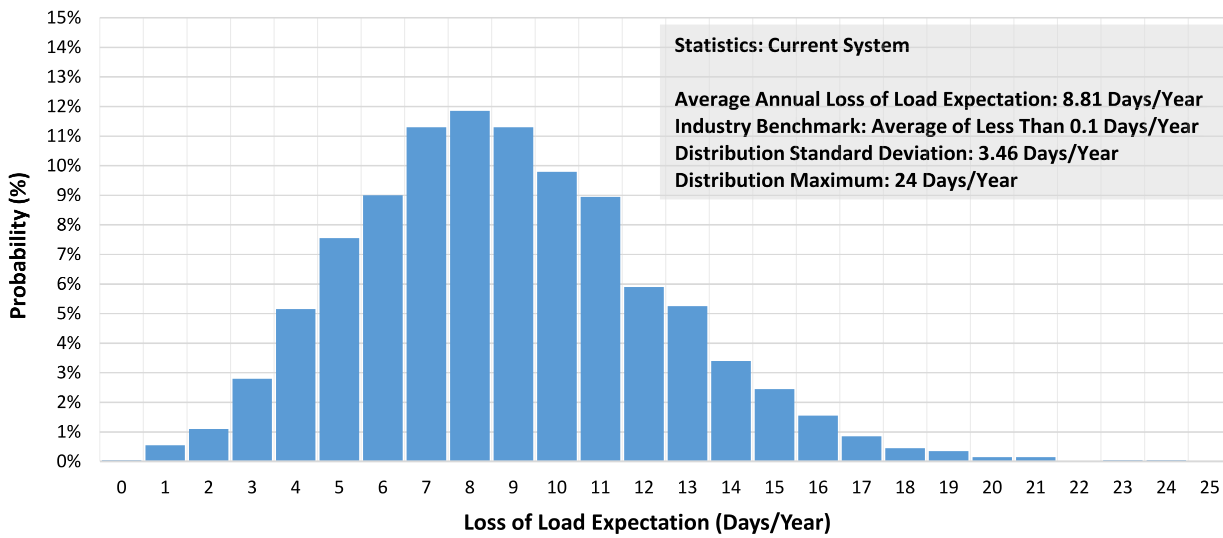
The loss of load expectation (LOLE) for Puerto Rico for FY2023, was calculated to be 8.81 days per year, meaning that on average, it is estimated that there will be 8.81 days per year where load will not be fully served by PREPA and other generators in FY2023. This measure is 88 times higher than the utility industry benchmark of 1 day in 10 years LOLE standard (0.10 days per year). The following table summarizes the LOLE and loss of load hours (LOLH) results of the analysis. LOLH reflect the expected average number of hours in FY2023 when there will be insufficient generation capacity available to serve demand. The results of the resource adequacy analysis confirmed that Puerto Rico does not meet the industry standard resource adequacy risk targets.

Table ES-1: Calculated Resource Adequacy Risk Measures, Current System (FY2023)

Measure	Generation Loss of Load Expectation (LOLE)	Generation Loss of Load Hours (LOLH)
Average	8.81 Days / Year	40.77 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The output of the analysis is a statistical distribution of how many days there is not enough generation capacity being produced by PREPA and the other generators to meet load. The characteristics of the distribution (i.e., distribution width, average) help to define the risk of the system not having sufficient available capacity to meet load for every hour. The following figure presents the results of the analysis.

Figure ES-1: Loss of Load Expectation Probability Chart, FY2023



The figure illustrates the calculated probability of how many days load will exceed PREPA's generation capacity in FY2023. Based on the distribution, 8 days of loss of load is the most likely outcome. There is approximately a 50% probability that the number of days of loss of load will be equal to or greater than 9 days. Note that the results do not forecast what will actually occur with respect to resource adequacy in FY2023; however, the figure does help to quantify the risk, or probability, of how many loss of load days are to be expected in FY2023. Note that an hour where there is a shortfall in generation capacity does not mean that the entirety of Puerto Rico will be without electricity for that hour. Instead, a forecasted deficit signifies that there is not enough generation to serve all load and thus some customers will experience electricity outages.

Compared to utility industry standards, the results for Puerto Rico have a "wide" distribution. In other words, there is a high probability of much greater than zero days per year LOLE. For reference, the most likely outcome for a system that can meet the utility industry target standard of a 0.1 days per year LOLE (when load is greater than generation capacity) would be zero days, as contrasted with 8 days for Puerto Rico.

Sensitivity Case: Vulnerability to Long-Term Loss of a Large Generator

The loss of a baseload generator for a long-term period has occurred repeatedly in recent years. For example, in the beginning of 2020 the earthquakes in southern Puerto Rico resulted in significant damage to the Costa Sur Power Plant. A separate simulation was performed to explore the risk of a long-term outage to the island's resource adequacy.

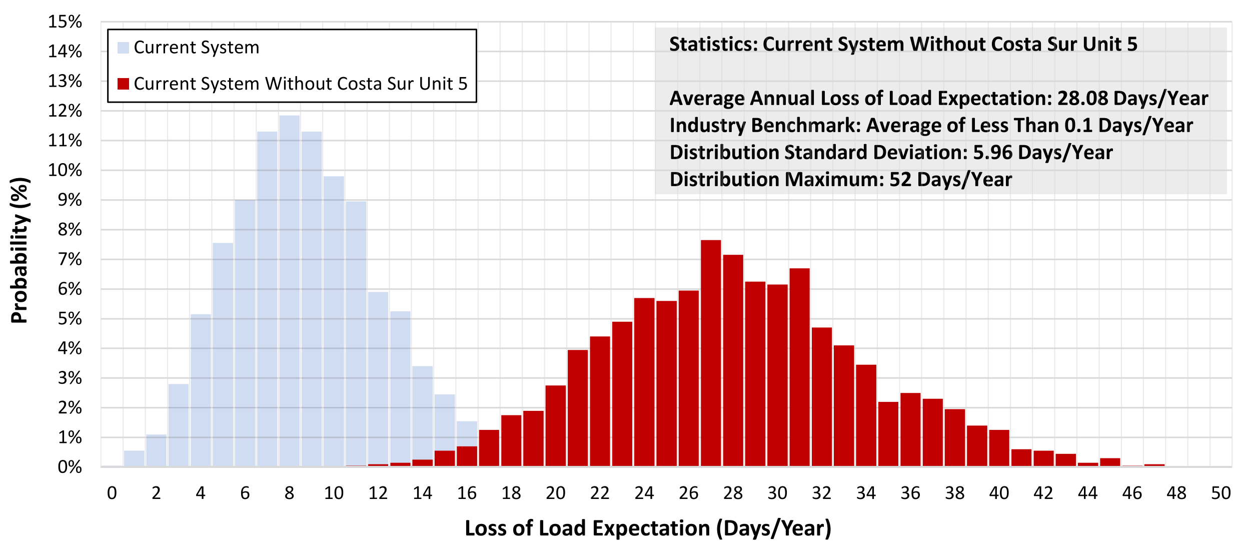
The simulation considered a scenario where there was a one-year outage to Costa Sur Unit 5 (a power plant with a nameplate rating of 410 MW but considered to have 350 MW of dispatchable capacity due to deratings). The results are summarized in the table below. The simulated loss of Costa Sur Unit 5 resulted in a sharp increase in LOLE and LOLH. The results clearly illustrate that Puerto Rico has little, if any, safety margin for its resource adequacy. The loss of a single large generator for an extended period would likely result in extended outages caused by insufficient generation supply to meet energy demand.

Table ES-2: Calculated Resource Adequacy Measures – Long-Term Loss of a Large Generator

Scenario	Generation Loss of Load Expectation (LOLE)	Generation Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System, but with Costa Sur Unit 5 Out for Entire Year	28.08 Days / Year	155.06 Hours / Year

The figure below presents the aggregated LOLE results of the probabilistic simulations for this scenario. It is worth noting that every simulation had at least 11 days with loss of load. Over 33% of the simulations resulted in at least 31 days with loss of load. Superimposed on the figure for comparison is the distribution from the system simulations prior to the long-term loss of a large generator.

Figure ES-2: Loss of Load Expectation Probability Chart – Long-Term Loss of a Large Generator



Conclusion

Given the significance of this issue, LUMA will continue to work with PREPA and other generators, as well as the Energy Bureau, Government of Puerto Rico, and our customers to take the necessary actions to help improve the resilience and reliability of the Puerto Rico electric system. Working together, and with a focus on addressing the risk of persistent generation shortfalls we can help build a better – and more reliable – energy future for all of Puerto Rico.

1.0 Introduction

This is the first resource adequacy analysis provided by LUMA Energy (LUMA) as operator of the transmission and distribution system and system operator (the "System Operator") with responsibilities for planning and transforming the utility to deliver a better, more reliable electrical system to the people of Puerto Rico. This report complies with LUMA's responsibility under the "Transmission and Distribution Operation and Maintenance Agreement" between the Puerto Rico Electric Power Authority (PREPA), P3A, LUMA Energy LLC, and LUMA Energy ServCo effective June 21, 2020. It is also a requirement of LUMA's operation and maintenance agreement, §5.13, (d) that LUMA "…prepare risk assessments and analyses in support of Resource Adequacy and Generation Project or Generation Supply Contract procurement prioritization and planning, which shall take into account the Integrated Resource Plan [IRP] and Applicable Law (and which assessments and analyses the Puerto Rico Energy Bureau [PREB] may request from time to time)."

The Puerto Rican electrical system is undergoing a significant transformation toward renewable energy and energy storage. Per the submission of the PREPA IRP in 2019 and PREB'S subsequent *Final Resolution and Order on the Puerto Rico Electric Power Authority's Integrated Resource Plan*, PREPA will integrate six tranches of solar photovoltaic (PV) or equivalent renewable energy, totaling 3,750 MW (megawatt[s]) and an additional 1,500 MW of energy storage. Work on the first two tranches is currently ongoing. With the integration of the solar PV and energy storage resources, the current expectation is that PREPA will be able to retire a significant quantity of its existing thermal generation.

The overall renewable energy transformation process will take many years to complete and is currently behind the originally forecasted schedule. To date, the first tranche of new renewable generation and energy storage is not in operation and thermal generator retirements have yet to occur. In the meantime, Puerto Rico's resource adequacy performance currently is extremely poor as power outages due to lack of available generation are a frequent occurrence on the island. While the renewable transformation process will help to improve future system resource adequacy, there are additional steps that can be taken to improve the system further and potentially realize near term benefits. This report is a first step in that process as it aims to identify the system challenges and vulnerabilities in Puerto Rico from a resource adequacy perspective.

The purpose of this report is to present an analytical framework and methodology to assess resource adequacy in Puerto Rico. Resource adequacy analysis is a basic requirement to understanding if the portfolio of generation resources can adequately meet customer needs and is performed in every North American Electric Reliability Corporation (NERC) region and most of the world's utilities. As mentioned above, it is also a requirement of LUMA's operation and maintenance agreement.

This first resource adequacy report documents the generation resource adequacy modeling process, results, and implications for the Puerto Rico electrical system. The focus of generation resource adequacy modeling is to determine if enough installed and operating generation capacity is available to serve system load during all hours of the day, throughout the study period, and to provide regulators with the quantitative tools and measures to ensure customers will receive safe reliable power supplies. The resource adequacy analysis determines if there is a deficit in generation resources, and from there, the regulator and policymakers must then approve a plan to address generation shortfall. The resource adequacy report itself does not specify the optimal generation technologies to fill any identified shortfall

(that is typically performed as part of the IRP process); however, the resource adequacy report is a critical input to the IRP analysis.

There are a consistent set of fundamental guidelines for performing resource adequacy analyses across the energy industry; however, there can be some variation in the analysis methodology based on the specific utility or planning region. In general, the key fundamentals of resource adequacy analyses can be summarized in the following points below:

- The goal of a resource adequacy analysis is to quantify how well the existing power plants in an electrical system are reliably able to serve electrical load.
- The analysis follows a probabilistic approach to assess the probability, or risk, that load might not be met by system generators.
- Results from the probabilistic analyses are compared to a resource adequacy target, which is defined as the acceptable level of risk that the generation portfolio might not be able to serve load. The target is typically set by the location's planning authority consistent with guidance provided by the regulator.
- The results and implications of a resource adequacy analysis are important tools that planners can use to help make decisions around generation retirements, additions, or other items related to how a utility can better serve electrical load.

The introduction section of this report provides an outline of the computational methodology for performing resource adequacy analyses in general, the methodology followed by other utilities in regions that share similarities with Puerto Rico, and the methodology used to assess generation adequacy in Puerto Rico. Note that generation resource adequacy is focused specifically on assessing generation deficiency across the system, not the constraints associated with electrical transmission and distribution systems; however, any transmission and distribution constraints will further hinder system reliability in addition to any deficiencies in generation resource adequacy.

1.1 Generation Resource Adequacy Analyses: An Overview

At a high level, resource adequacy analyses quantify the risk that an electrical system is unable to serve system load because of deficient generation capacity. Resource adequacy guidelines for utilities are influenced by numerous agencies, which include the Federal Energy Regulatory Commission, the NERC, state/territory governments, and other regional regulating authorities. The unique needs of each utility have created complex and varying resource adequacy requirements across the industry. Ultimately, it is the responsibility of the regulator to approve the resource planning targets proposed by the utility and the plan to achieve those targets, often through an IRP process. In Puerto Rico, the regulatory authority is PREB.

The calculations to evaluate a system's resource adequacy are rooted in a probabilistic approach to quantify the risk that system generators will be unable to fully serve system load. The analysis considers several important variables, such as power plant generation capacity, generation derates and outages, generation intermittency, system electrical load, among other items.

Resource adequacy requirements and calculations are often incorporated into IRPs. Resource adequacy analyses inform resource planners whether there is enough installed generation capacity, and this is often represented through a generation planning reserve margin (PRM). The PRM is defined as the amount by which the total system generation capacity exceeds peak electrical demand. For a given system, higher

PRMs typically equate to a lower risk that load will not be served during a given timeframe; however, higher PRMs also correspond to higher costs. Note that a PRM is set based on a target system reliability and may differ from utility to utility based on the unique characteristics of each location. Resource adequacy analyses can also help inform additional planning criterions that may exist for a utility, such as a requirement to have enough generation to cover the loss of the largest generator in the system or requirements to meet different reserve margins for summer versus winter seasons.

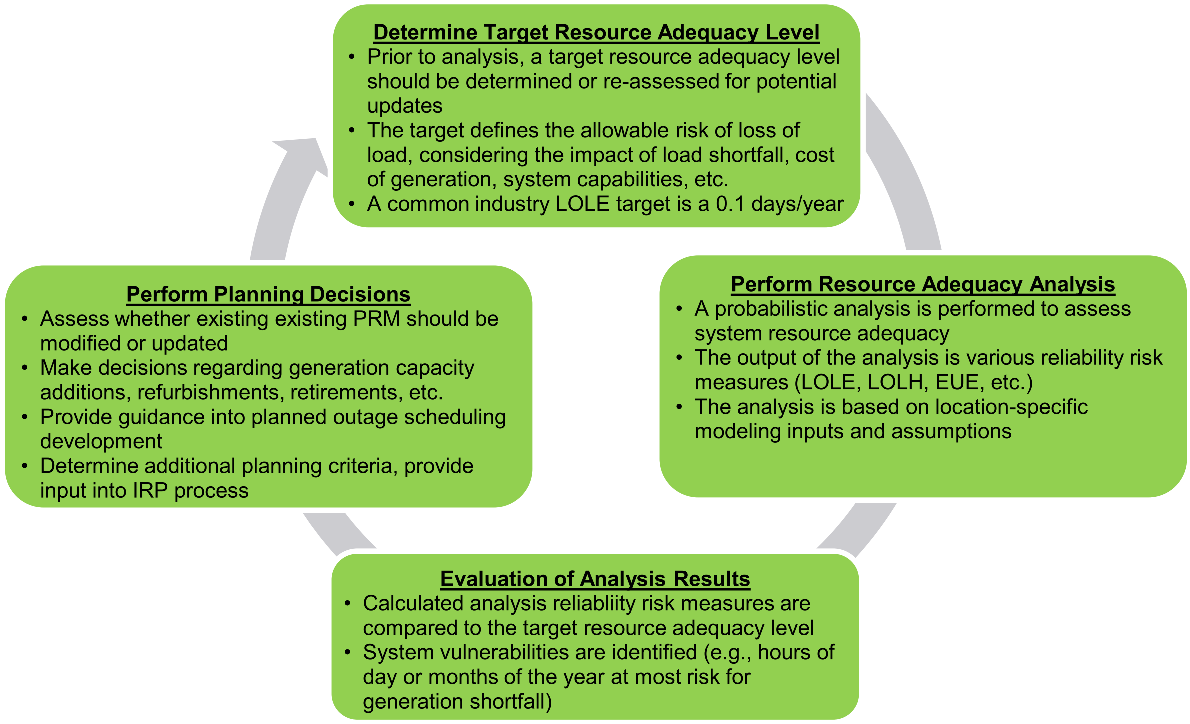
Resource planners often must balance a set of goals, such as minimizing the risk of not serving electrical load, costs, environmental impacts, etc., to develop a resource plan that represents the needs and priorities of their jurisdiction in a cost effective but resilient manner. From there, the analysis can help guide planners on various decisions, including whether to add generation capacity, incentivize demand response and behind-the-meter (BTM) programs, retire generators, and/or improve outage rates of specific units through rehabilitation (asset renewal) projects.

1.1.1 Generation Resource Adequacy Process

The process of performing a resource adequacy analysis is summarized in the following figure. The analysis is used to quantify the risk that the available generation capacity[1] will be unable to serve electrical demand. The risk is summarized using resource adequacy risk measures, which are discussed in the next section. From there, the risk is compared against the adequacy target for the utility or planning region. Based on how well the analyzed system performs related to the target, decisions and planning associated with generation additions, retirements, PRMs, and other items can be made.

[1] Available or dependable generation capacity measured MW is calculated based on generator production profile and technology specific effective load carrying capabilities.

Figure 1-1: Resource Adequacy Process Flowchart



Multiple tools are used to conduct resource adequacy modeling in the industry, including spreadsheet-based tools, production cost modeling software, and commercial simulation software tools.

The results of resource adequacy analyses are often dependent upon numerous assumptions, and therefore vary by utility or planning region. Resource planners may evaluate a range of load forecast scenarios to assess resource sufficiency to meet these different growth scenarios. Similarly, a range of weather scenarios may be assessed, given the increasing impact of weather to variable renewable generation sources as utilities transition to carbon-free generation. Finally, the frequency and duration of planned maintenance or forced outages significantly impact the risk that load might not be served by the system's generators.

1.1.2 Generation Resource Adequacy Risk Measures

When considering the output of a resource adequacy analysis, it is important to understand the key measures that define system performance. There are several different measures to consider, and the specific definitions and applications of reliability risk measures are not uniform throughout the industry. Each region of the country has different generation portfolios and load characteristics and different risk factors, which will result in different targets. For example, the Pacific Northwest has large amounts of hydropower, California is extremely vulnerable to wildfires and import/export limitations, and New England has limited access to natural gas supplies. The key reliability measures for the purposes of this analysis are in the table below. Each measure represents different aspects of a system's reliability including the frequency, duration, and magnitude of generation shortfall events.

Table 1-1: Resource Adequacy Risk Measures

Resource Adequacy Risk Measure	Definition
Loss of Load Hour (LOLH)	The expected number of hours within a given time horizon (usually one year) when a system's hourly demand is projected to exceed the available generating capacity.
Loss of Load Expectation (LOLE)	The expected number of days in the time horizon (usually one year) for which available generation capacity is insufficient to serve the demand. LOLE measures the number of days in which involuntary load shedding can be expected to occur, regardless of the number of consecutive or non-consecutive LOLHs in the day. For example, if there are two days in a year where there is insufficient generation to serve load (regardless of the duration of the outage or how many events occur in a single day), then LOLE would equal two days per year.
Loss of Load Probability (LOLP)	The probability of demand exceeding the available generation capacity during a given period. For example, if a resource adequacy analysis considered 1,000 unique annual simulations of an electrical system and a 5% LOLP target was to be met, loss of load could only be observed in 50 of those simulations.
Expected Unserved Energy	The summation of the expected number of megawatt (MW) hours of load that will not be served in a specific time interval because of demand exceeding the available generation capacity. This energy-centric measure considers the frequency, magnitude, and duration for all hours of the period.

Note that an hour where there is a shortfall in generation capacity does not mean the entire island of Puerto Rico will be without electricity for that hour. Instead, it signifies that there is not enough generation to serve all load on the island and thus some customers will experience electricity outages.

1.1.3 Computing System Resource Adequacy

A resource adequacy analysis is probabilistic in nature. As such, its output is typically processed in accordance with regulatory oversight to derive the probability, or risk, that an electrical system would be unable to serve system load over a specified period. An industry-approved probabilistic iterative method was used to assess the resource adequacy of Puerto Rico's electric grid. Using this method, all hours of fiscal year 2023 (FY2023) were simulated, calculating whether there will be sufficient available generation capacity to meet load for each hour of every day. Since some of the variables that impact a power plant's ability to generate electricity are random (for example, the timing of forced outages), the year is re-simulated thousands of times. By evaluating the aggregated output of all simulations, one can quantify the risk of not meeting system load due to resource capacity deficiency. All scenarios analyzed considered 2,000 iterations as this was a threshold at which results were considered statistically converged. Convergence was determined by considering average loss of load hours (LOLH) of all completed iterations and how that value changed with subsequent iterations. Once the change in average LOLH with each subsequent iteration fell below an acceptable threshold, the simulations were considered converged. Additional information on simulation convergence is provided in Appendix 7.

1.2 Resource Adequacy Regulatory Guidance

Support for probability-based resource adequacy assessments has increased due to changing electrical load profiles, the growth of intermittent (renewable) resources, shifting peak hour demand, and other

factors that impact resource adequacy. Recent NERC surveys[2] indicate that most electrical regions in North America are using probabilistic approaches to examine resource adequacy questions, and if they are not, they are considering incorporating probabilistic approaches. Resource adequacy analyses inform planning reserve margin decisions, generator additions and retirements, integrated resource planning, market-based resource procurement, and other system planning activities.

In 2017, the Federal Energy Regulatory Commission approved NERC Reliability Standard BAL-502-RF-03[3], which created requirements for entities registered as planning coordinators to perform and document resource adequacy analyses. The standard describes that a PRM should be based on an adequacy criterion such that the average expectation of loss of load across a large number of simulations for the same planning year, but under different generator outage conditions, is equal to 0.10 days per year. This target is also known as the “one day in 10-year” criterion since it means that on average only 1 day in every ten years will experience a shortfall resulting in load-shed. This resource adequacy standard also provides guidance to include load forecast characteristics, resource characteristics, and transmission limitations that prevent delivery of generation reserves in the resource adequacy analysis. Note that Puerto Rico is not under NERC jurisdiction; however, the NERC standards are useful guidelines for the island.

The growth of variable generation sources, such as wind and solar power plants, has resulted in electrical planners having to think carefully about how best to capture the electrical capacity contributions provided by each energy resource technology with respect to resource adequacy calculations. In March 2011, NERC released a guideline report, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*.[4] This report identified the need for alternative approaches rooted in probabilistic analysis when determining variable generation capacity contributions towards availability and resource adequacy. Further, the report recommended the comparison of adequacy study results based on alternative metrics than solely PRM.

Continuing this expanding resource adequacy guidance, NERC released the 2018 technical reference report, *Probabilistic Adequacy and Measures*.[5] Due to the evolving resource mix landscape as a result of increasing penetration levels of variable generation, this technical reference report focused on identifying, defining, and evaluating more probabilistic approaches and risk measures to provide insights into resource adequacy assessments. Resource evaluation planning approaches range from relatively simple calculations of PRMs to extensive generation resource adequacy simulations that calculate system loss of load probability (LOLP) values.

1.3 Resource Adequacy and Electric System Resiliency

This document focuses on resource adequacy pertaining to normal system operating conditions. Resource adequacy performance can also be analyzed for non-normal, or adverse operating conditions. Hurricanes, tropical storms, earthquakes, and other similar disasters would be defined as adverse operating conditions. An industry term typically associated with infrastructure preparedness and performance during and after adverse operating conditions is “resiliency.” White House Presidential

[2] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.
[3] North American Electric Reliability Corporation, Standard BAL-502-RF-03, October 2017.
[4] North American Electric Reliability Corporation, Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, March 2011.
[5] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.

Policy Directive 21,[6] which focuses on critical infrastructure security and resilience, defines system resiliency as,

> The term 'resilience' means the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.

As such, a resilient system is one that is designed not only to be able to withstand adverse operating conditions, but also to be able to recover quickly. Robust resiliency planning is essential to help minimize the negative impacts caused by a high severity event. This is especially true on an island since it is not possible to import electricity from a neighbor in the aftermath of a disaster. While evaluating electrical system resiliency in the face of adverse operating conditions is not a focus of this report, generation resource adequacy is an important part of resiliency planning, and the tools and methodology presented in this report can be used to help quantify the effectiveness of resiliency measures.

Generator and power system resiliency are intricately tied to generation resource adequacy; however, the methodology and assumptions for analyzing resource adequacy for normal operating conditions differ from those tied to analyzing resource adequacy during high severity events. Given high severity events are also often defined by a cascade of system failures, there may be other failures within the electrical system that arise during the event. Failures and challenges such as transmission outages, fuel supply disruptions, flooding, etc., can all place significant stress on the ability of available generators and system equipment to serve load. There is a separate work steam related to system resiliency ongoing in Puerto Rico currently being supported by the U.S. Federal Emergency Management Agency.

1.4 Generation Adequacy for Different Utilities

A comparison of resource adequacy approaches for various other utilities and planning entities that have similarities to Puerto Rico is provided in this section of the report and in Appendix 3. Utilities and planning entities considered in this review were selected based on having similar characteristics to Puerto Rico, including other islands, similar geographic location and climate, and similar renewable integration goals.

1.4.1 Resource Adequacy for Other Islands

Maintaining high levels of system resource adequacy is especially challenging for islanded systems. The main reason for this is that islands are not able to import electricity from neighboring utility systems during times of peak demand and/or deficient generation capacity. In contrast, a utility on the U.S. mainland would generally be able to import electricity from neighbors when needed. In addition, many islands, including Puerto Rico, have a relatively small number of total generators available to be dispatched at any point in time. As a result, islands are often at a high risk of not being able to serve load in the event of a loss of a large generator, due to the simple fact that there is a limited number of other generators that could be dispatched to cover for the large generator's outage. In contrast, planning regions and large utilities in the U.S. mainland can have hundreds, and sometimes thousands, of other generators that could be dispatched to cover for power plant outages.

[6] Presidential Policy Directive -- Critical Infrastructure Security and Resilience, The White House, Office of the Press Secretary, February 12, 2013.

Table 1-2: Resource Adequacy Comparison by Location

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or Similar Values)
Virgin Islands Water and Power Authority	1 day per year in 2020, reducing 1 day per 10 years in 2044[1]
Hawaiian Electric Company	Energy Reserve Margin, based on 1 day per 4.5 years[2]
Guam Power Authority	1 day per 4.5 years[3]

Sources:

1. VIWAPA Final IRP Report, 21 July 2020.
2. Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.
3. Guam Power Authority Integrated Resource Plan, FY2013.

1.4.2 U.S. Virgin Islands

As one of Puerto Rico's island neighbors, the U.S. Virgin Islands has several similarities to Puerto Rico from a generation resource adequacy perspective. Neither can import electricity from neighbors (as would be the case on the U.S. mainland), both have similar climates, and both have similar renewable energy goals. The utility that operates the electrical system for the U.S. Virgin Islands, the Virgin Islands Water and Power Authority (VIWAPA), released an updated IRP in 2020 where they discussed several items related to the resource adequacy considerations for the Virgin Islands.[7] The IRP planning horizon spanned 2020-2044 and notes the requirement that 50 percent of electricity generation in the U.S. Virgin Islands (as a percentage of peak demand) must come from renewable resources by 2044. VIWAPA's resource adequacy planning criteria sets a loss of load target of 1 day per year in 2024, which gradually reduces to 0.10 days per year by 2044. In addition, VIWAPA has an "N-1-1" planning criterion, which requires sufficient installed generation capacity to be available during the loss of two of the largest generators, or key transmission lines.

1.4.3 Hawaii

From generation resource adequacy perspective, Hawaii also has several similarities with Puerto Rico. They cannot import electricity from neighbors, have similar climates, and both are undergoing the integration of more renewable resources. The Hawaiian Electric Company (HECO) operates the electrical system in Hawaii. HECO's resource adequacy considerations are summarized in a recent filing with the Hawaiian Public Utility Commission, titled the 2021 Adequacy of Supply.[8] In the filing, HECO notes some recent modifications to their resource adequacy planning criteria, namely the implementation of an "energy reserve margin" (ERM) concept for the purposes of examining resource adequacy in all hours of the year. The ERM is defined as the percentage of excess system capacity over system load in each hour and accounts for Hawaii's inability to import emergency power from a neighboring utility. The ERM is rooted in HECO's guideline of requiring the system loss of load expectation (LOLE) to be less than one day per 4.5 years.

[7] VIWAPA Final IRP Report, 21 July 2020.
[8] Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.

The ERM concept being used by HECO includes contributions from variable renewable generators, energy storage, demand reduction programs, and other similar resources. HECO defines the dependable contributions from renewable generators to resource adequacy probabilistically, based on the following equation:

$$Dependable\ Capacity_{Hourly} = Average\ Generation_{Hourly} - N \cdot (Standard\ Deviation)$$

Here the hourly dependable capacity of the renewable generator is equal to that generator's historical production for that hour, reduced by the standard deviation of the historical production. The value of *N* is set by HECO to be 1 for wind generators and 2 for solar generators. For example, if a solar power plant on average has generated 100 MW (megawatt[s]) at noon, but with a standard deviation of 20 MW, then only 60 MW would be considered as dependable capacity (100 MW – 2 x 20 MW = 60 MW) at noon.

1.4.4 Guam

Guam's electrical system is operated by the Guam Power Authority. As an island with a similar climate to Puerto Rico, Guam shares many similar resource adequacy challenges as Puerto Rico. Guam Power Authority is currently undertaking the process to develop an updated IRP; however, previous IRP filings note the island targets a one day per 4.5 years LOLE resource adequacy risk measure.[9] Guam Power Authority indicates that at least a 54% PRM is required to meet this level of resource adequacy. Guam Power Authority also utilizes an "N-2" planning criteria, requiring sufficient generation to cover the loss of the island's two largest generating sources.

[9] Guam Power Authority Integrated Resource Plan, FY2013.

2.0 Puerto Rico's Electrical System and Resource Adequacy

2.1 Puerto Rico's Power Plants

The size, number, availability, and generating characteristics of the installed power plants in an electrical system are some of the most important inputs into resource adequacy analyses. Puerto Rico's electricity comes from three different sources:

1. Thermal power plants, or power plants that consume fossil fuels
2. Renewable power plants, such as solar, wind, and hydroelectric
3. BTM generators, such as solar panels on residential homes, or other similar sources

The following subsections provide an overview of each of the above items, including considerations for how they impact overall system resource adequacy analyses.

2.1.1 Puerto Rico's Thermal Power Plants

Puerto Rico's electric system currently has an installed nameplate, front-of-the-meter generating capacity of approximately 5,000 MW[10] (System Operations uses an effective capacity for planning and dispatch of 5,124 MW, not including renewables); however, due to extended outages of certain power plants and derates,[11] only about 4,200 MW are currently operational. Approximately 95% of the operating generating capacity comes from dispatchable fossil fuel-fired generators (also known as thermal generators), including power plants that consume natural gas, oil, coal, and diesel fuel. The remaining generating capacity comes from renewable resources, predominantly solar, which sums to approximately 200 MW of nameplate capacity. In addition, Puerto Rico has approximately 455 MW of installed BTM generation (for example, solar panels on the roofs of homes), which is primarily solar.

The table that follows summarizes the operating thermal generating resources and shows their historical forced outage rates for reference (compiled from data between 2013 and 2021). Forced outage rates are defined as the percentage of time the power plants are broken down and unable to generate electricity. From a resource adequacy perspective, there are several important points to note in the following table. First, the forced outage rates of many of the existing thermal power plants have historically been very high, with approximately 2,000 MW of Puerto Rico's installed generators having historic forced outage rates of over 15% (and many of these generators having forced outage rates of 30% or more). For reference, the average equivalent forced outage rate for North American power plants is 7.17%.[12] Since a generator that is broken down is unable to generate electricity, the higher the forced outage rates, the higher the risk that there will be a shortfall in generation capacity needed to serve system load. The duration of a forced outage is also a very important consideration for resource adequacy. Repairs after a forced outage can be made quickly, or can take many months, as was the case with the Costa Sur Power Plant following the damage it sustained during the January 2020 earthquakes. For this analysis, the

[10] This value excludes any BTM generating capacity, for example, solar panels on the roofs of residential homes.
[11] A derated unit is a unit that is not able to operate at its design output level but can operate at a lower output level.
[12] North American Electric Reliability Corporation, 2021 State of Reliability: An Assessment of 2020 Bulk Power System Performance, August 2021.

duration of a forced outage for each thermal plant was assumed to be 40 hours, which represents an average repair time.[13]

Additionally, many of the power plants were first constructed over 50 years ago, and many of these generators have not been properly maintained. This not only is the culprit of the high forced outage rates, but also results in power plant operators needing to take more frequent and longer scheduled maintenance outages than might otherwise be expected for a power plant of similar type and vintage that had been sufficiently maintained. As opposed to forced outages, scheduled maintenance outages can be planned for; however, a scheduled outage still results in the power plant being unable to generate electricity, which increases the risk that there will not be enough total system capacity needed to serve system load.

One additional cause of plant outages (or limited power plant operation) is thermal power plant emissions. The U.S. Environmental Protection Agency regulates power plant emissions and requires Puerto Rico's generators to have emissions under federally mandated levels for certain combustion by-products (e.g., NOx, SO_2, particulates). Some of Puerto Rico's thermal power plants are unable to continuously comply with the U.S. Environmental Protection Agency regulations, and as a result are either required to shut down to make improvements that will improve emissions, or limit operation. For this analysis, units that are inoperable due to emissions restrictions are considered inactive; however, units that are operable, but operationally restricted, are considered as available dispatchable capacity in this analysis. Operationally restricted units are considered to still be able to contribute towards meeting system load because these units still can operate for short periods when there would otherwise be loss of load.

Each of the thermal power plants listed in the following table is modeled for the resource adequacy calculations documented in this report, including the available capacity, historical forced outage rate, and any scheduled maintenance outages.

Table 2-1: Summary of Expected Operating Thermal Generators in FY2023

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Historic Forced Outage Rate (%)
AES 1	2002	Coal	227	227	3
AES 2	2002	Coal	227	227	3
Aguirre Combined Cycle 11	1977	Diesel	296	220	40
Aguirre Combined Cycle 21	1977	Diesel	296	100	30
Aguirre Steam 1	1971	Bunker	450	370	10
Aguirre Steam 2	1971	Bunker	450	350	10
Costa Sur 5	1972	Natural Gas	410	350	10
Costa Sur 6	1973	Natural Gas	410	350	15
EcoEléctrica	1999	Natural Gas	530	530	2

[13] A sensitivity analysis around modeled generator forced outage duration was performed and is documented in Appendix 8. The findings indicated that for a consistent set of generator forced outage rates, differences in the modeled generator forced outage duration resulted in reasonably small differences in calculated LOLE and no discernable differences in LOLH.

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Historic Forced Outage Rate (%)
Palo Seco 3	1968	Bunker	216	190	15
Palo Seco 4	1968	Bunker	216	160	15
San Juan 7	1965	Bunker	100	70	30
San Juan 9	1968	Bunker	100	95	10
San Juan Combined Cycle 5	2008	Diesel / Natural Gas	220	200	7
San Juan Combined Cycle 6	2008	Diesel / Natural Gas	220	200	7
Cambalache 2	1998	Diesel	82.5	76	10
Cambalache 3	1998	Diesel	82.5	75	10
Mayagüez 1	2009	Diesel	55	50	30
Mayagüez 2	2009	Diesel	55	50	30
Mayagüez 3	2009	Diesel	55	50	30
Mayagüez 4	2009	Diesel	55	50	30
Palo Seco Mobile Pack 1-33	2021	Diesel	27 each (81 total)	81	9
7 Gas Turbines (Peakers)4	1972	Diesel	21 each (147 total)	147	40
Total			**4,981**	**4,218**	—

Notes:

1. The steam cycle on both the Aguirre Combined Cycle power plants are currently inoperable, repair timing is uncertain
2. Mayagüez 1 is currently out of service but is expected come back into service sometime in 2022. This analysis considers it will come back into service on January 1, 2023.
3. The Palo Seco Mobile Pack units are expected to return to service sometime in 2022. This analysis considers they will come back into service on January 1, 2023.
4. A total of 18 gas turbines, each with a capacity of 21 MW, are installed. Only 7 are considered to be operational

2.1.2 Puerto Rico's Renewable Power Plants

The table below summarizes the operating front-of-the-meter renewable power plants installed in Puerto Rico. Solar and wind are the primary sources of renewable energy in Puerto Rico. Note that Puerto Rico has a small fleet of hydroelectric power plants with a design capacity of approximately 100 MW. Most of these units date back to the 1930s and 1940s, many are not operational or are in disrepair, and the few that do operate experience high forced outage rates (50% or higher). After accounting for long-term outages / damage and unit limitations, the effective capacity of these units typically only hovers around 20 MW. For this reason, the hydroelectric plants are not listed in the following table and are also not considered for the resource adequacy analyses documented in this report.

Since renewable generators have periods of intermittent electricity production, it was important to determine the amount of hourly renewable generation that could reliably be considered as available to serve load from a resource adequacy perspective. The methodology used in these analyses shares

similarities to the methodology employed by HECO and in California, as described earlier. For these analyses, actual historical generation data from each of the renewable power plants listed in the table below was analyzed. From there, each generator's ninetieth percentile lowest production level for each hour was identified. To capture the fact that renewable generators are able to produce more electricity in some months than others (i.e., solar generation is typically higher in the summer months), two different ninetieth percentile generation levels were identified for each month, one for the first half of the month and one for the second half of the month. This methodology captured the contributions of the renewable generators to improving system resource adequacy from a statistical framework, accounting for the intermittency of the generators. It was also fundamentally based on the actual historical production levels of the existing renewable generators.

Table 2-2: Summary of Operating Renewable Generators

Generator Name	Commercial Operation Date	Fuel	Nameplate Capacity (MW)
AES Ilumina	2012	Sun	20
Fonroche Humacao	2016	Sun	40
Horizon Energy	2016	Sun	10
Yarotek (Oriana)	2016	Sun	45
San Fermin Solar	2015	Sun	20
Windmar (Cantera Martino)	2011	Sun	2.1
Windmar (Vista Alegre / Coto Laurel)	2016	Sun	10
Pattern (Santa Isabel)	2012	Wind	75
Fajardo Landfill Tech	2016	Methane Gas	2.4
Tao Baja Landfill Tech	2016	Methane Gas	2.4
Total			**226.9**

2.1.3 Puerto Rico's Behind the Meter Generation Resources

The table below shows the estimated amount of generation that is installed BTM across the different regions of Puerto Rico (as of Q1 2022). BTM generation is broken down between resources connected to the distribution system and resources connected to the transmission system; both of which are primarily composed of rooftop solar.

These BTM resources are considered in the analysis as reductions in system load.[14]

[14] Note that based on NERC Standard BAL-502-RF-03, BTM resources should not counted as a contribution towards resource adequacy. It is recommended that future resource adequacy analyses of the island consider a probabilistic methodology of accounting for a dependable MW level of these resources or conservatively ignore their contributions

Table 2-3: Summary of BTM Generation by Area

Area	BTM Generation Connected to the Distribution System (MW)	BTM Generation Connected to the Transmission System (MW)
Arecibo	25	7
Bayamon	60	12
Caguas	47	14
Carolina	33	9
Mayaguez	31	2
Ponce East	15	10
Ponce West	36	6
San Juan	119	30
Total	**366**	**90**

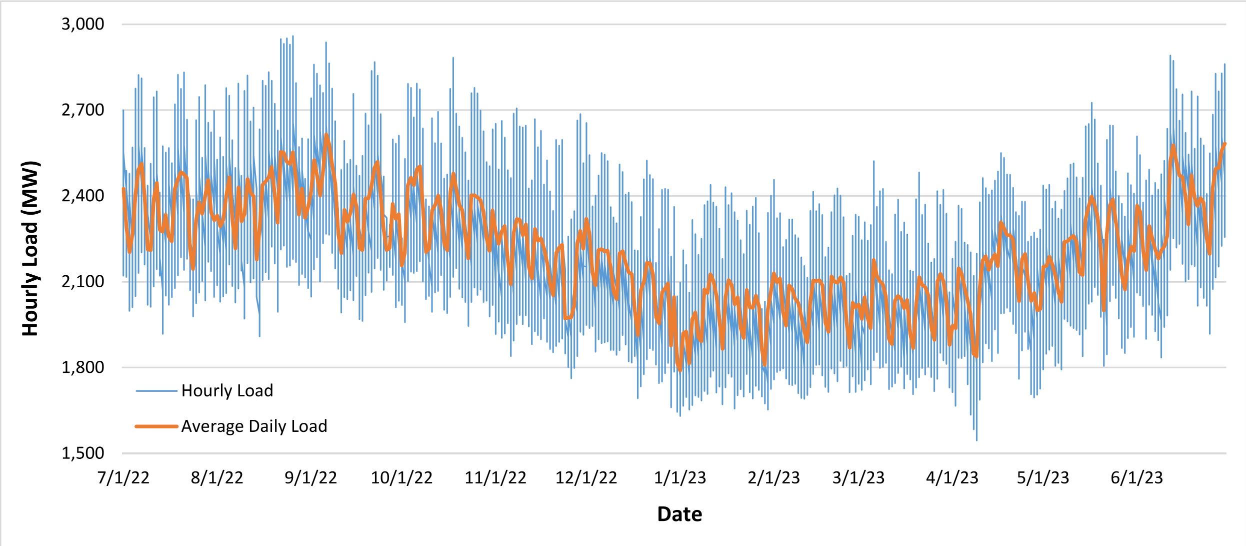
2.2 Puerto Rico Electrical Load / Demand

The electrical demand, also referred to as load, is another important element in resource adequacy evaluations, specifically because system generators must be able to meet the electrical demand for every hour. Puerto Rico's electrical demand varies for each hour of the day, throughout the year. The Puerto Rico load profile considered for the resource adequacy calculations described in this report is based on both LUMA forecasts of the FY2023 monthly peak load and aggregated energy values. The projection is done for each month based upon the coming period's expected weather, economic activity, and other macro-economic factors. The macro-economic factors are consistent with projections utilized for the Puerto Rico's fiscal planning process for FY2023. It should be noted that demand has been forecasted based on average historical temperatures. Higher-than-average temperatures would be expected to lead to higher peak demand, reduced reserve margins and a higher risk of insufficient generation to meet system load. LUMA's peak load and aggregate energy forecasts for FY2023 are converted to hourly values using the historical hourly load profile from 2021. The forecasted hourly load profile for FY2023 used for all calculations in this analysis is provided in the figure below. Figure 2-1 plots each hour in FY2023.

Some key attributes to note about the load profile are both the hourly variability and the seasonality of the profile, with summer and early fall months having higher load than other times during the year. The reason for this is that summer and the early fall months are the hottest in Puerto Rico; thus, electrical consumption from air conditioning and other cooling tends to drive up total system electrical usage.[15]

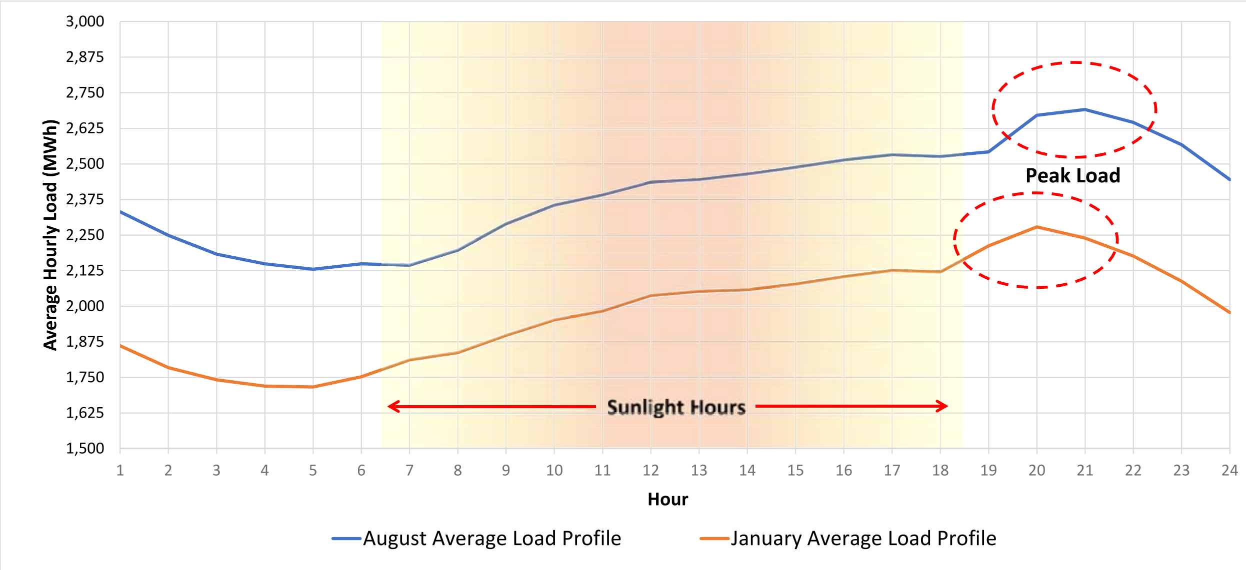
[15] For future analyses it is recommended that a statistical approach to load forecasting based on weather data be considered. A methodology that considers a distribution of potential system loads levels based on Puerto Rico's historic weather data would better capture potential load variability for the island and its impact to resource adequacy.

Figure 2-1: Forecasted FY2023 Electrical Load Profile for Puerto Rico



An important characteristic of the load profile in Puerto Rico is how it varies over the different hours of the day. The following figure illustrates this variance by presenting hourly load profile, averaged over each day, for the months of August 2022 and January 2023 (the highest and lowest load months, respectively). As can be observed in the figure, load steadily rises over the course of the day, peaking in the evening. From a resource adequacy perspective, the hourly load profile is important because it identifies when generation is needed most. The fact that the load profile peaks in the evening also highlights a challenge that many other utilities with large amounts of solar generation are currently facing: stand-alone solar power plants are unable to contribute generation to help meet the evening peak since the sun would have already set. Solar power resources must be paired with energy storage in order to contribute generation during the evening peak. The size and duration of the storage systems is an important consideration in determining if solar resources will contribute to resource adequacy at peak.

Figure 2-2: Forecasted FY2023 Electrical Load Profile – Hourly Averages



The load, and/or the hourly load profile, in Puerto Rico may change moving forward. On one hand, energy efficiency plans, demand reduction programs, the growth of BTM generation, and other similar items have the potential to reduce overall system load; however, other items such as electric vehicle adoption have the potential to increase system load. For this reason, continued identification of the critical times during the day and over the course of the year when load is high will be important moving forward for resource adequacy considerations.

2.3 Puerto Rico's Reserve Margin

A comparison of the forecasted electric demand in Puerto Rico, which peaks at approximately 3,000 MW, to the total nameplate generation capacity of the Puerto Rico electric system, which averages near 5,000 MW, indicates that the PRM for Puerto Rico is approximately 65% (1 – 5,000 MW / 3,000 MW). In general, this PRM is in line with other similarly sized islands. For example, in Hawaii, HECO reported that on Oahu the margin of available capacity to peak load was approximately 60% in 2020.[16]

Given the fact that Puerto Rico's PRM is generally in line with other similarly sized islands (many that achieve high performance with respect to resource adequacy), one might draw the conclusion that resource adequacy is not a significant challenge in Puerto Rico. This thinking is mistaken. The reason for this is that a focus on PRM from one location to another ignores location-specific variables that can have a significant impact on the ability for a utility to serve load in the location. For example, in Hawaii the generator forced outage rates are significantly lower than in Puerto Rico. As a result, generators in Hawaii are able to operate much more reliably with fewer generator outages than those in Puerto Rico. NERC notes this fact in *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning:*[17]

> Unless the Planning Reserve Margin is derived from an LOLP (loss of load probability) study, there is no way to know what level of system risk is present. This is because some generators have higher forced outage rates than others. Therefore, one system with a 15 percent Planning Reserve Margin may not be as reliable as another system even though it also has a 15 percent Planning Reserve Margin.

As a result, given the high outage rates and derates of the existing power plants in Puerto Rico, a simple comparison of the PRM in Puerto Rico to the PRM values in other similar locations masks the significant challenges Puerto Rico faces on a daily basis with respect to generation resource adequacy. It is correct that there is a substantial amount of generation installed in Puerto Rico; however, the majority of that generation is unreliable and too frequently incapable of operating when electricity is needed.

The methodology utilized in this report to assess resource adequacy for Puerto Rico is based on the probabilistic approach. As NERC noted in their survey of various planning regions and utilities, "most assessment areas are already using or are considering probabilistic approaches to assess emerging reliability issues."[18]

[16] Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.
[17] North American Electric Reliability Corporation, Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, March 2011.
[18] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.

3.0 Resource Adequacy Analysis Results and Implications

Resource adequacy analyses of the Puerto Rican electric system were performed using both a PROMOD model adapted for resource adequacy calculations (PROMOD is a generator and electric portfolio simulation software maintained by Hitachi Energy) and the PRAS model, a probabilistic resource adequacy simulation tool adapted for the Puerto Rican electrical system.

The methodology followed for all calculations is consistent with the descriptions provided in the previous sections of this report (also see Appendix 2 for a more detailed explanation of the calculation framework and equations). The goal of the calculations was to quantify Puerto Rico's electrical system performance and to establish a baseline set of resource adequacy measures for the existing electrical system, which would then allow for comparison to other similar planning regions and utilities and help guide system planning decisions.

A thorough validation process was undertaken to validate the results of the analysis. A discussion of the validation process and results are provided in Appendix 7.

3.1 Resource Adequacy Results

FY2023 was simulated on an hourly basis to calculate if there is sufficient available generation capacity to meet load for each hour of the day. Since forced outages to power plants occur randomly, FY2023 is re-simulated 2,000 times, with each simulation considering forced outages occurring at different times. The results of the analysis are presented both in this section and also in greater detail in Appendix 12 through Appendix 16.

Considering that as an island, Puerto Rico is unable to rely on electricity imports to support grid stability, and that the island's generators are generally unreliable, Puerto Rico faces challenges in meeting industry standard resource adequacy risk targets. This analysis confirmed this reality, as the probability that Puerto Rico's generators would be unable to meet system load over the course of a year was calculated to be nearly 100%.[19] In addition, the LOLE in Puerto Rico was calculated to be 8.81 days/year, indicating that on average, one can expect a generation shortfall (i.e., "loss of load") to occur 8.81 days in FY2023. This LOLE is significantly higher than other LOLE targets adopted in the energy industry, including those adopted by similar islands. For reference, this calculated LOLE is 88 times higher than a commonly accepted 1 day in 10 years LOLE industry standard (0.10 days per year). The following table summarizes the results of the analysis.

[19] Loss of load probability, LOLP, calculated based on 2,000 Monte Carlo simulations (i.e., in approximately 100% of the simulations, a loss of load event occurred).

Table 3-1: Calculated Resource Adequacy Risk Measures, Current System (FY2023)

Measure	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Average	8.81 Days / Year	40.77 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—
Distribution Standard Deviation	3.46 Days / Year	21.69 Hours/ Year
Distribution Maximum	24 Days / Year	146 Hours / Year

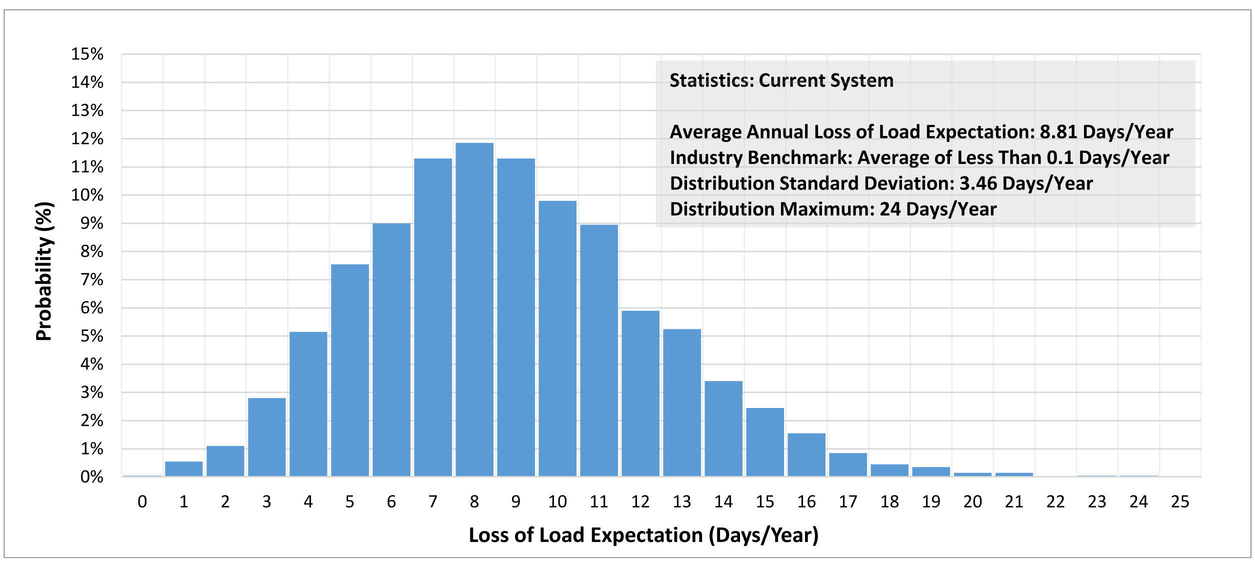
As expected for a small islanded system, the analysis demonstrates that outages to individual generators, whether planned or unplanned, have a significant impact on the electrical system's ability to reliably meet load. For comparison, a large U.S. mainland utility or planning region with hundreds of generators is more easily able to manage outages to individual generators given that there are many other available generators that can be brought online to make up for the lost generation.

3.1.1 Loss of Load Expectation Distribution Review

As previously mentioned, the average LOLE of 8.81 days per year is significantly higher than the standard industry benchmark of 0.10 days per year. An equally important item to note is the high standard deviation in the LOLE results. There were a significant number of simulations where the LOLE was greater than 10 days per year. The figure below presents this information, organizing the results of the simulations for FY2023.

Based on the distribution, 8 days of loss of load is the most likely outcome. There is approximately a 50% probability that the number of days of loss of load will be equal to or greater than 9 days. The figure does not forecast what will actually occur with respect to resource adequacy in FY2023; however, the figure does help to quantify the risk, or probability, of how many loss of load days might be expected in FY2023. Note that one simulation had 24 days of loss of load, which was the highest of all the simulations performed.

Figure 3-1: Loss of Load Expectation Probability Chart, FY2023



Various characteristics of the Puerto Rico electric system help explain the wide distribution in LOLE:

- The forced outage rates for the existing power plants are generally very high, meaning the power plants break down frequently. If different power plants happen to break down at the same time, which is common in Puerto Rico, then there is significant risk that there will not be enough remaining generators available to cover the load. As power plants go down for outages (whether planned or forced), the remaining power plants must increase output to meet system load. This places some level of additional stress on the remaining power plants, which can compound risks of loss of load if the remaining power plants happen to break down more frequently as a result of the additional stress or are required to take more frequent planned maintenance.
- In addition, the power plants in Puerto Rico sometimes require prolonged planned maintenance outages due to their poor current condition. Whenever a power plant is on a planned maintenance outage, it is unable to generate electricity.
- As a relatively small island, Puerto Rico is both unable to import electricity from neighbors, and has a limited number of power plants that can generate electricity. By comparison, a larger utility on the U.S. mainland can not only import electricity from neighboring utilities during times of need, but also has many available power plants that can be started or ramped up to meet load in times of need. In Puerto Rico, the loss of a single large power plant (either for planned maintenance or a forced outage), like EcoEléctrica, the Aguirre Steam units, Costa Sur, or AES, immediately reduces the total available generating capacity in Puerto Rico by roughly 10%. If one of these units is out of service, electricity must be supplied by other generators, many of which are either already being fully utilized, or are unreliable and break down frequently.

3.1.2 Loss of Load Hours Breakdown

The following figure presents the average number of LOLH for all the simulations, broken out by hour of the day. In the figure, if one were to sum each individual hour, it would total 40.77 LOLH, which is the average annual LOLH over all the simulations. The majority of LOLH are observed during the evening hours, when system load is highest and when solar production is diminished or unavailable to the electric system. Approximately 55% of the observed LOLH in the resource adequacy simulation were observed to occur between 7 p.m. and 11 p.m.

From the perspective of improving system resource adequacy, the results indicate that the most effective solutions will be those targeted at being able to help meet load during the evening peak. For example, additional stand-alone solar generators should be able to help overall system resource adequacy, but only during times when the sun is up, which reflects just over a third of the hours when the simulated LOLH were found to occur. In contrast, an energy storage system, reciprocating engine, or other dispatchable unit would be better able to provide energy during the evening peak load; thus, would be most effective at improving overall system resource adequacy.

Figure 3-2: Calculated Loss of Load Hours Broken Out by Hour of the Day

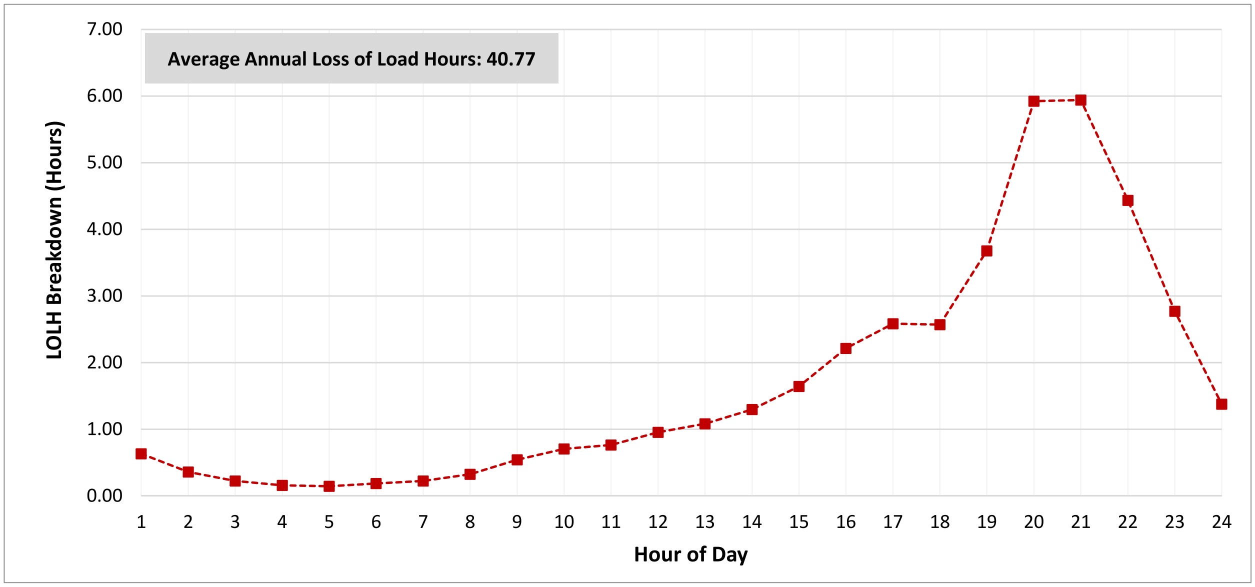
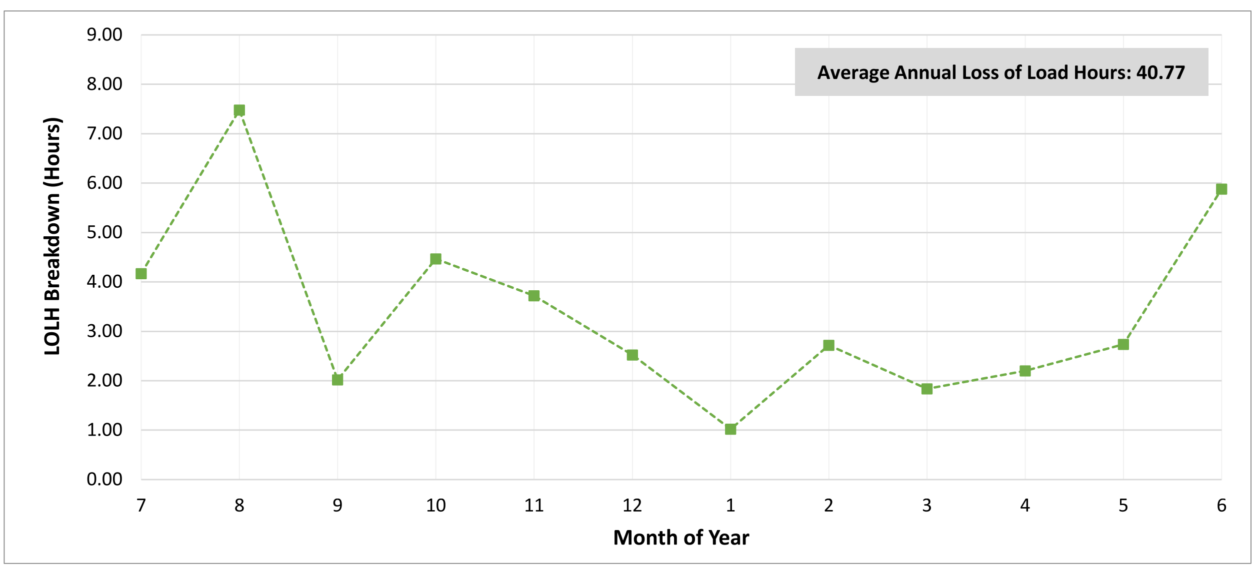


Figure 3-3 below shows LOLH broken out by month. LOLH were found to be highest during July, August, and June (2023), primarily because these months correspond to high system load. An additional contribution to LOLH is maintenance outages of large generators. During maintenance outages of large generators, any additional forced outages to other generators could result in LOLH. This is the case for the higher LOLH in October 2022, as this is when EcoEléctrica will be in a maintenance outage.

In general, while planned outages to large generators can result in higher LOLH risk, it is difficult to reschedule outages to large generators in Puerto Rico in a different way that would result in a significant improvement to the annual resource adequacy performance of the system. The reason for this is because there are only so many times when the generators can be scheduled to minimize the impact to the system and the generators often require extended maintenance time due to their age and condition.

Figure 3-3: Calculated Loss of Load Hours Broken Out by Month of the Year



3.1.3 Calculated Reserve Margin

The average system reserve margin by hour and month was calculated, based on an average over all the simulations performed. This information is illustrated in the following figure. Each input in the figure reflects the ratio of available capacity to load during that hour and month. Available capacity includes both the available capacity of thermal generators and any dependable capacity from operating renewable generators.

Times that correspond to higher LOLH risk are highlighted in various shades of red, the darkest times corresponding to highest LOLH risk. The values in the table are the average over all simulations. In general, times when the ratio of available capacity to load drops below 1.60 correspond to a higher risk of demand not being served in Puerto Rico. The ratio of average available capacity to load is lowest in the summer months, during the evenings, where it averages under 1.30.

Figure 3-4: Ratio of Capacity to Load

Hour of Day	Month of Year: 7	8	9	10	11	12	1	2	3	4	5	6	Average
1	1.47	1.45	1.54	1.51	1.56	1.59	1.72	1.59	1.62	1.60	1.52	1.46	**1.55**
2	1.53	1.50	1.59	1.56	1.62	1.66	1.79	1.66	1.68	1.67	1.58	1.51	**1.61**
3	1.58	1.54	1.63	1.60	1.67	1.70	1.83	1.71	1.73	1.73	1.63	1.55	**1.66**
4	1.61	1.57	1.66	1.63	1.69	1.73	1.86	1.74	1.75	1.77	1.67	1.58	**1.69**
5	1.62	1.58	1.68	1.64	1.70	1.74	1.86	1.74	1.76	1.78	1.68	1.60	**1.70**
6	1.61	1.57	1.65	1.61	1.67	1.70	1.82	1.69	1.73	1.75	1.67	1.58	**1.67**
7	1.62	1.57	1.65	1.60	1.64	1.65	1.77	1.64	1.70	1.74	1.66	1.57	**1.65**
8	1.58	1.54	1.63	1.58	1.62	1.65	1.74	1.61	1.66	1.67	1.59	1.51	**1.62**
9	1.53	1.49	1.57	1.53	1.58	1.60	1.69	1.56	1.62	1.62	1.54	1.46	**1.56**
10	1.50	1.46	1.55	1.50	1.54	1.57	1.65	1.53	1.60	1.59	1.51	1.43	**1.54**
11	1.49	1.44	1.52	1.48	1.52	1.56	1.63	1.52	1.58	1.57	1.50	1.43	**1.52**
12	1.48	1.42	1.50	1.45	1.50	1.53	1.59	1.51	1.56	1.55	1.48	1.41	**1.50**
13	1.48	1.41	1.48	1.43	1.48	1.52	1.58	1.50	1.55	1.54	1.47	1.41	**1.49**
14	1.46	1.40	1.46	1.42	1.46	1.52	1.58	1.50	1.55	1.54	1.46	1.40	**1.48**
15	1.44	1.38	1.44	1.40	1.44	1.50	1.56	1.48	1.53	1.52	1.44	1.38	**1.46**
16	1.42	1.36	1.43	1.38	1.41	1.48	1.54	1.46	1.50	1.49	1.42	1.36	**1.44**
17	1.40	1.35	1.42	1.37	1.39	1.45	1.52	1.44	1.47	1.47	1.41	1.36	**1.42**
18	1.39	1.34	1.42	1.37	1.39	1.43	1.51	1.43	1.47	1.46	1.41	1.36	**1.42**
19	1.39	1.33	1.40	1.31	1.30	1.35	1.45	1.40	1.45	1.45	1.40	1.35	**1.38**
20	1.33	1.27	1.36	1.30	1.29	1.34	1.40	1.35	1.37	1.39	1.33	1.30	**1.34**
21	1.30	1.26	1.36	1.31	1.31	1.36	1.43	1.36	1.38	1.39	1.32	1.28	**1.34**
22	1.31	1.28	1.38	1.33	1.35	1.39	1.47	1.39	1.41	1.41	1.34	1.30	**1.36**
23	1.34	1.31	1.42	1.38	1.40	1.44	1.53	1.44	1.46	1.45	1.37	1.33	**1.41**
24	1.40	1.38	1.48	1.45	1.49	1.51	1.62	1.50	1.53	1.52	1.44	1.38	**1.47**
Average	**1.47**	**1.42**	**1.51**	**1.46**	**1.50**	**1.54**	**1.63**	**1.53**	**1.57**	**1.57**	**1.49**	**1.43**	**1.51**

The figure above illustrates that while the PRM in Puerto Rico is around 65% (see Section 2.3), due to high forced outage rates of the generators on the island, the ratio or actual available capacity to load is substantially lower.[20]

3.2 Impact of a Long-Term Loss of a Large Generator

Given the current condition of the existing power plants in Puerto Rico, the loss of a baseload generator for a long-term period is not a low probability risk. In fact, this happened fairly recently when the

[20] A recommended PRM was not determined as this first report instead focused on assessing the current resource adequacy performance on the island. It is recommended that future versions of this analysis consider what PRM (or similar metric) Puerto Rico should target.

earthquakes in southern Puerto Rico in the beginning of 2020 resulted in significant damage to the Costa Sur power plant. The power plant was forced to take a long-term outage while repairs were made. Given the risk of a long-term outages, a separate simulation was performed exploring the risk of a long-term outage to the island's resource adequacy.

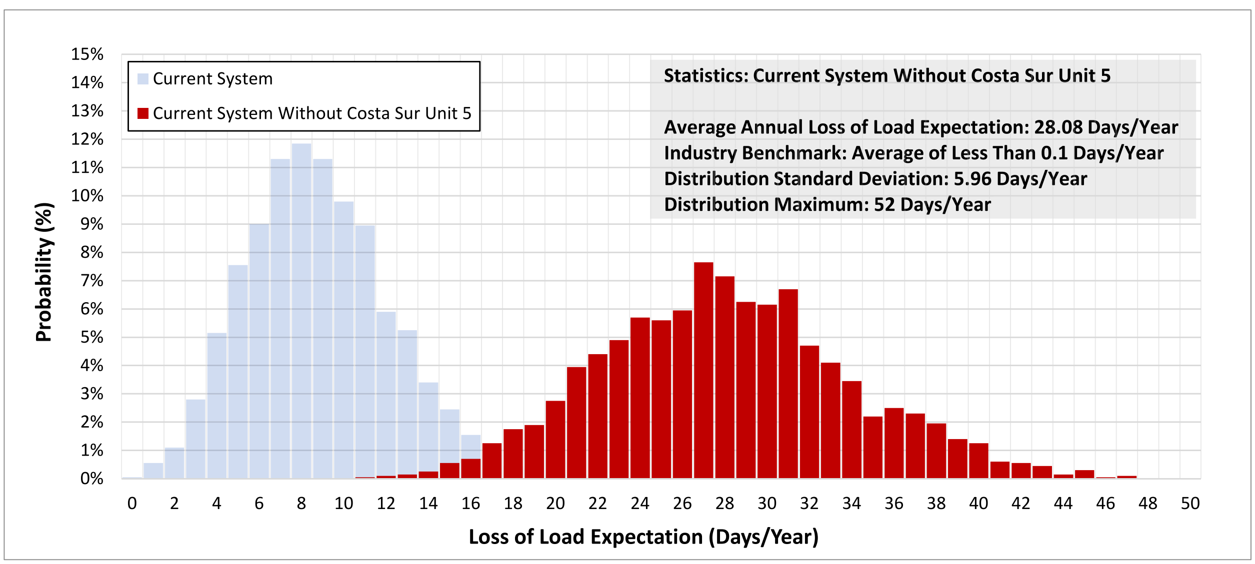
The simulation considered a scenario where there was a one-year outage to Costa Sur Unit 5, which is a power plant with a nameplate rating of 410 MW. For this simulation, Costa Sur Unit 5 is simulated as having 350 MW of dispatchable capacity due to deratings. All other variables associated with the scenario were unchanged from those discussed in previous sections of this report. The results are described below. The simulated loss of Costa Sur Unit 5 resulted in a sharp increase in days of loss of load (LOLE) and LOLH. The results clearly illustrate that Puerto Rico has little, if any, net margin from a generation perspective.

Table 3-2: Calculated Resource Adequacy Measures – Long-Term Loss of a Large Generator

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System, but with Costa Sur Unit 5 Out for Entire Year	28.08 Days / Year	155.06 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The figure below presents the aggregated LOLE results of the simulations for this scenario. It is worth noting that every simulation (out of the 2,000 performed) had at least 11 days of loss of load. A total of 33% of the simulations resulted in at least 31 days of loss of load. Superimposed on the figure is the distribution from the current system simulations for comparison.

Figure 3-5: Loss of Load Expectation Probability Chart – Long-Term Loss of a Large Generator



3.3 Comparison of Puerto Rico's Historical Available Capacity

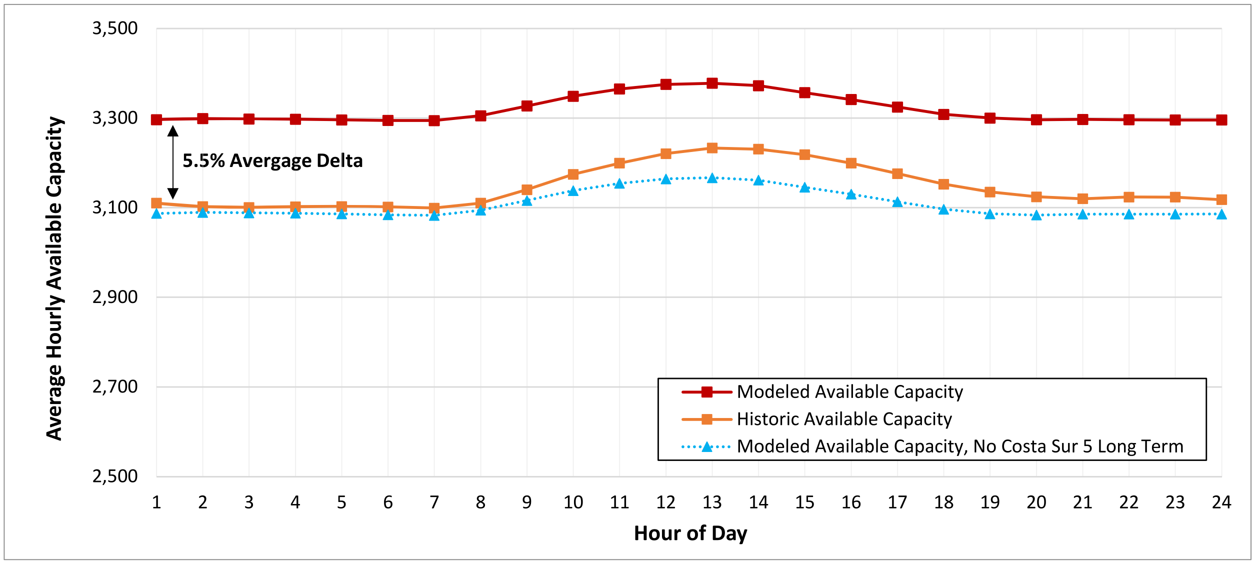
A comparison of Puerto Rico's historical available capacity to the model results. The following figure provides a comparison of the three items listed below:

- Historical available capacity (thermal + renewable generators) for every hour over the last 12 months
- Modeled available capacity (thermal + renewable generators) for the current system, for every hour simulated in FY2023. The modeled available capacity accounts for forced outages, planned outages, and derates.
- Modeled available capacity (thermal + renewable generators) for the current system, but including a long-term loss of Costa Sur Unit 5, for every hour simulated in FY2023 (Costa Sur 5 is modeled as having 350 MW of capacity, derated from the unit nameplate of 410 MW). The modeled available capacity accounts for forced outages, planned outages, and derates.

The data is aggregated and averaged by hour of the day.

As can be seen, the modeled available capacity for the current system is higher than the historical. The current system model shows approximately 200 MW (averaging 5.5%) of additional capacity available for every hour than what was actually experienced historically over the last 12 months. The modeled scenario that considered a long-term outage to Costa Sur Unit 5 better aligns much better with historical data.

Figure 3-6: Comparison of Historical Available Capacity to Model



A key takeaway from the above graph is that the current system model outputs likely portray somewhat more optimistic performance from the perspective of resource adequacy than what has historically been experienced. Historic available capacity has much more closely resembled the scenario considering a long-term outage to Costa Sur Unit 5. There are numerous reasons for the difference in available capacity, including difference between historic and future planned outages, forced outage durations, and a number of generators that are expected to become operational in FY2023 that were not operational

over the last 12 months, namely Mayagüez Unit 1 (55 MW) and the Palo Seco Mobile Pack Units 1, 2, and 3 (27 MW each, for a total of 81 MW).

3.4 Meeting Resource Adequacy Industry Benchmarks

There is currently a significant gap between where Puerto Rico currently is with respect to generation resource adequacy and typical industry targets. As described in the previous section, the analysis of the current system indicates an LOLE of 8.81 days/year on average, which is approximately 88 times higher than the traditional LOLE industry benchmark of 0.10 days/year. A separate analysis was performed to identify the magnitude of additional generation that would result in the system achieving a 0.10 days/year LOLE.

An analysis was performed considering the addition of 'perfect' generation capacity, which we define below:

> **Perfect Capacity.** Generation capacity that is always available, 100% of the time, for each hour of the year. This capacity can also be considered as a constant reduction of system load for every hour of the year for the purposes of a resource adequacy analysis.

Note that perfect capacity is not associated with a specific generation technology type; however, for illustrative purposes it would theoretically be equivalent to a battery storage system that was always 100% charged (i.e., never had to be charged), regardless of how often it was discharged, or an engine / combustion turbine that never took maintenance outages or broke down. From a conceptual framework, determining the amount of perfect capacity needed in Puerto Rico provides a first-order assessment of the system improvement needed to meet the 0.10 days/year LOLE resource adequacy target.

The analysis was completed by adding various amounts of perfect capacity to the resource adequacy model and re-running the analysis. The analysis was complete once the amount of perfect capacity that resulted in the system LOLE equaling 0.10 days/year was determined. The results of the simulation determined that 675 MW of perfect capacity would result in an LOLE of 0.10 days/year. Results are summarized in the following table.

Table 3-3: Calculated Resource Adequacy Risk Measures – Perfect Capacity Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System + **675 MW** of Perfect Capacity	0.10 Days / Year	0.36 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

Given that no generation technology can operate as a perfect generator, the actual amount of capacity required for the system to meet a 0.10 days/year would be somewhat higher than the 675 MW identified above. The size of the new generating resource would also vary by generator technology type. As an example, a larger capacity of solar photovoltaic (PV) paired to energy storage would need to be added for the system to meet a 0.10 days/year LOLE target than capacity from combustion turbines, reciprocating engines, standalone energy storage (storage that can charge from the grid, regardless of the generation source), or other similar technologies, due to the fact that solar PV can only generate electricity during the

daytime. Modifications to existing generators that improved reliability would also help to improve overall system resource adequacy.

The following figures provide more detail regarding the results of the analysis, particularly with respect to LOLH on both an hourly and monthly basis. The figures compare the current system to the system with the additional 675 MW of perfect generation capacity. As can be seen, the addition of the 675 MW significantly improves the overall electrical system from the perspective of generation resource adequacy.

Figure 3-7: Comparison of Loss of Load Hours Broken Out by Hour of the Day

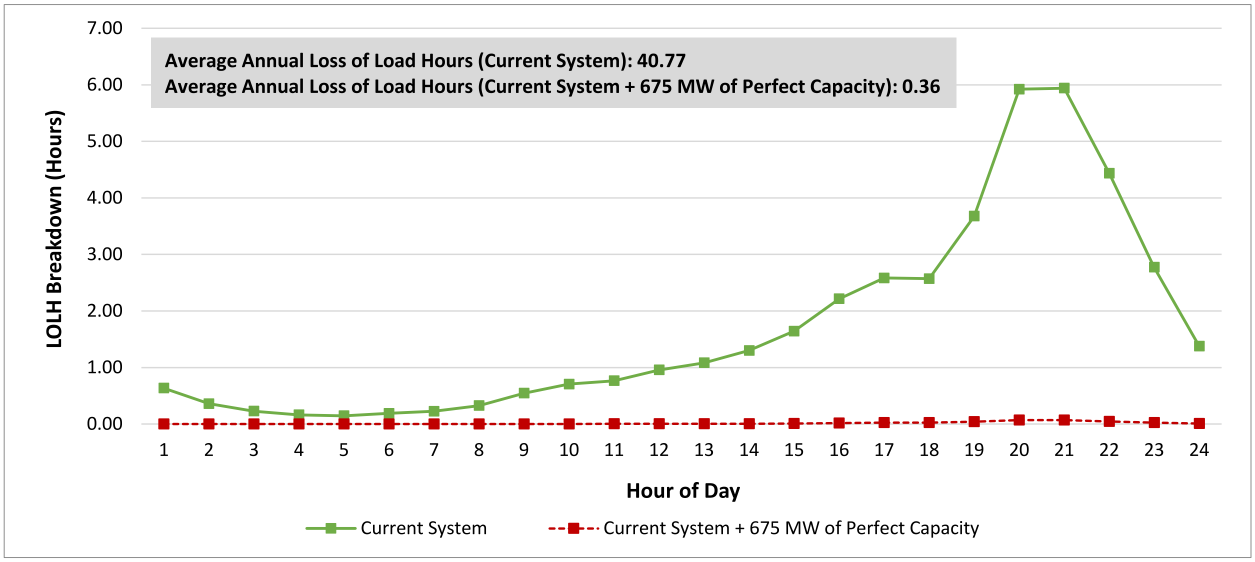
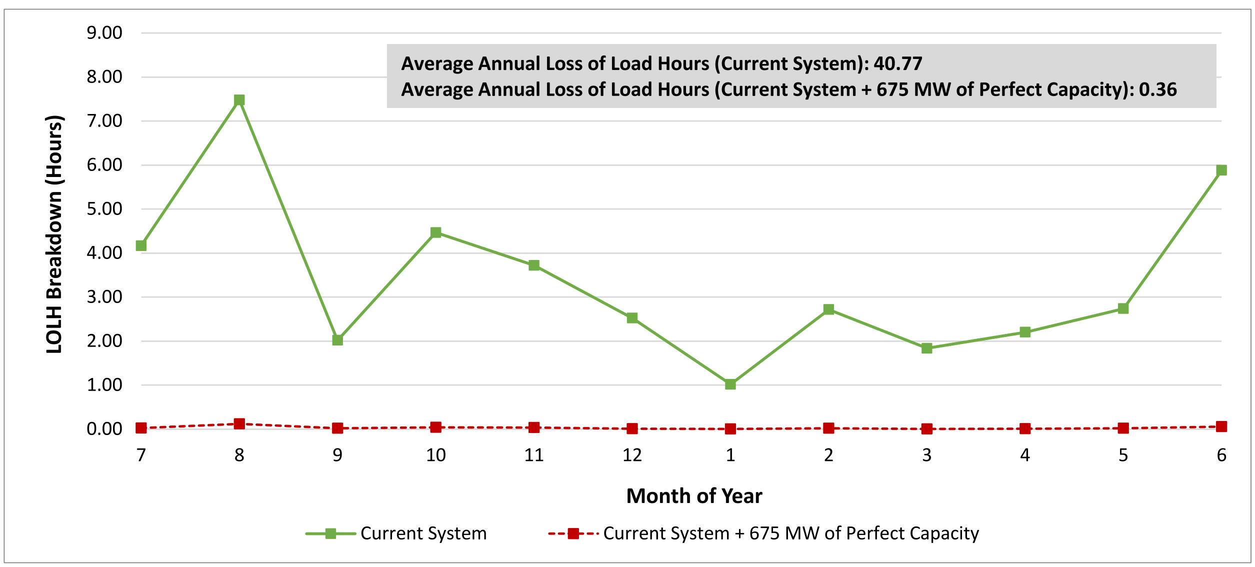


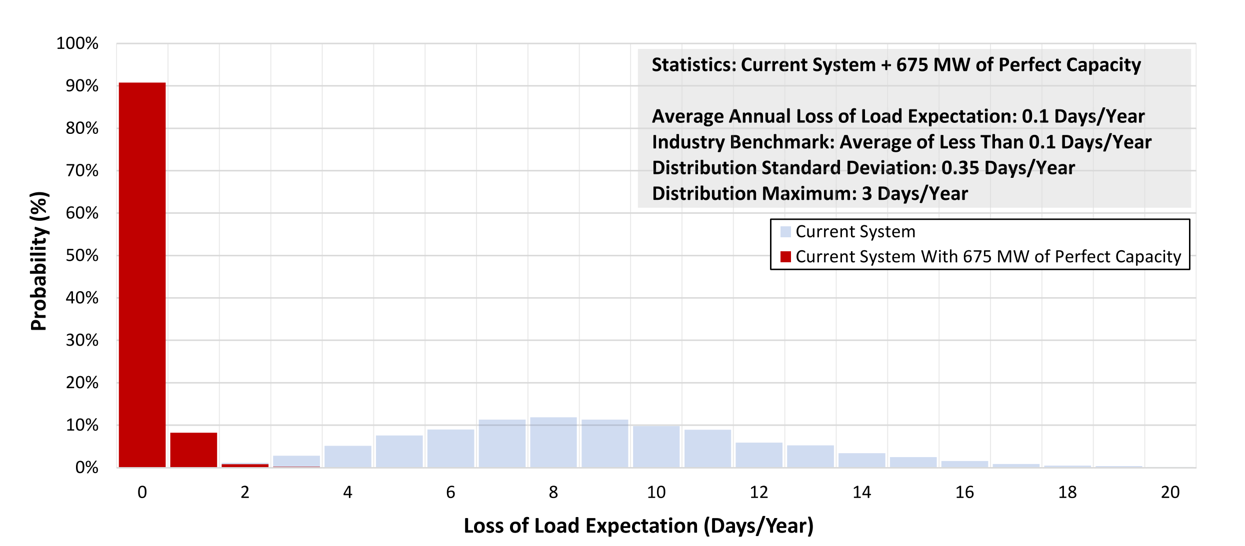
Figure 3-8: Comparison of Loss of Load Hours Broken Out by Month of the Year



The figure below presents the aggregated LOLE results of the simulations for the scenario with the additional 675 MW of perfect capacity included in the overall generation portfolio. Only 9% of the

simulations performed were found to have days where there was loss of load. Superimposed on the figure is the distribution from the current system simulations for comparison.

Figure 3-9: Loss of Load Expectation Probability Chart – Perfect Capacity Addition



3.5 Additional Sensitivity Analyses

A number of additional sensitivity analyses are described in Appendix 23 through Appendix 28 of this report. A list of those additional analyses is provided below:

- **New Solar PV Addition.** This sensitivity simulation illustrates the resource adequacy impact of adding new solar generation to the current system model in varying MW levels. For this sensitivity, all added solar is assumed to be standalone solar, meaning none of the MW are considered to be paired with energy storage. Separate sensitivity simulations which consider energy storage are listed below.
- **New Standalone Battery Energy Storage System (BESS) Addition.** This sensitivity simulation illustrates the resource adequacy impact of adding standalone BESS to the current system model in varying MW levels.
- **New Solar Paired with BESS Addition.** This sensitivity simulation illustrates the resource adequacy impact of adding new solar generation paired with BESS to the current system model in varying MW levels.
- **New Flexible Thermal Resources.** This sensitivity simulation illustrates the resource adequacy impact of adding new flexible thermal resources (i.e., engines, combustion turbines, etc.) to the current system model in varying MW levels.
- **New Demand Response Resources.** This sensitivity simulation illustrates the resource adequacy impact of adding demand response (DR) resources (i.e., short-term reductions in system load) to the current system model in varying MW levels.
- **Energy Efficiency Load Reduction.** This sensitivity simulation illustrates the resource adequacy impact of various levels of energy efficiency initiatives that result in system electrical demand reductions.

Appendix 1. Resource Adequacy Risk Measures Introduction

The key reliability measures for the purposes of this analysis are presented in the table below. Each measure represents different aspects of a system's resource adequacy including the frequency, duration, and magnitude of generation shortfall events.

Table A-1: Resource Adequacy Risk Measures

Resource Adequacy Risk Measure	Definition
Loss of Load Hour (LOLH)	The expected number of hours within a given time horizon (usually one year) when a system's hourly demand is projected to exceed the available generating capacity.
Loss of Load Expectation (LOLE)	The expected number of days in the time horizon (usually one year) for which available generation capacity is insufficient to serve the demand. LOLE measures the number of days in which involuntary load shedding occurs, regardless of the number of consecutive or non-consecutive LOLHs in the day. For example, if there are two days in a year where there is insufficient generation to serve load (regardless of the duration of the outage or how many events occur in a single day), then LOLE would equal two days per year.
Loss of Load Probability (LOLP)	The probability of demand exceeding the available generation capacity during a given period. For example, if a resource adequacy analysis considered 1,000 unique annual simulations of an electrical system and a 10% LOLP target was to be met, loss of load could only be observed in 100 of those simulations.
Expected Unserved Energy (EUE)	The summation of the expected number of megawatt (MW) hours (MWh) of load that will not be served in a specific time interval because of demand exceeding the available generation capacity. This energy-centric measure considers the frequency, magnitude, and duration for all hours of the period.

The measures identified above are used to quantify a system's performance from the perspective of resource adequacy, allowing one to compare performance to a benchmark performance target or other locations. The mathematical definitions of the above measures are provided in the following appendix.

Appendix 2. Resource Adequacy Risk Measures Calculations

Resource adequacy risk measures are used by system planners to identify future needs and inform decision-making. When determining the optimum level of generating resources, system planners may consider financial costs, environmental impacts, technology types, market designs, or other drivers. This report references NERC's 2018 *Probabilistic Assessment and Measures Report*[21] as the basis for the selection of the probabilistic resource adequacy risk measures, including recommended computational approaches and definitions. For this report, a Monte-Carlo computational method was used to calculate LOLE and LOLH, computing all hours (8,760) of the FY2023 study year (July 1, 2022, until June 30, 2023).

The resource adequacy risk measures are used to quantify the loss of load, or amount of demand not served, to evaluate system resource adequacy. Loss of load at hour *i* in the *kth* Monte Carlo iteration is defined as follows:

$$LOL_{ki} = \max\{0, L_i - \sum_{Gen=j}^{m} G_{jk}\}$$

Where L_i is the load in hour *i*, G_{jk} is the available capacity of the generator in the *kth* Monte Carlo iteration, and *m* is the number of generators in the system. LOL_{ki} is the loss of load amount in hour *i*, in the *k*th iteration (in MW).

Loss of Load Hours

LOLH is defined as the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. LOLH is calculated by counting the number of hours where there is loss of load in each iteration:

$$LOLH_k = \sum_{Hour\ i=1}^{H} B_{ki}$$

Where $LOLH_k$ is the loss of load duration in the *kth* iteration, *i* represents each hour, *H* is the total number of hours in the study period (8,760), and B_{ki} is a Boolean variable representing whether there is demand not supplied in hour *i* in the *kth* iteration, defined below:

$$B_{ki}(LOL_{ki}) = \begin{cases} 0\ if\ LOL_{ki} = 0 \\ 1\ if\ LOL_{ki} \neq 0 \end{cases}$$

LOLH for the entire simulated year can then be calculated using the following equation:

$$LOLH = \frac{1}{N}\sum_{k=1}^{N} LOLH_k$$

[21] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.

Where *k* represents the Monte Carlo iteration and *N* is the total number of Monte Carlo iterations.

Loss of Load Expectation

LOLE counts the days that have loss of load events, regardless of the number of consecutive or non-consecutive LOLH in the day. For example, if there is one LOLH in a day, or two LOLH in a day, both equate to 1 day of loss of load from a LOLE perspective. LOLE is the expected number of days per year for which available generation is insufficient to serve demand at least once per day.

$$LOLE\ days/year = \frac{1}{N}\sum_{k=1}^{N}\sum_{d=1}^{D} E_{k,d}$$

Where *d* represents the day, *D* is the total number of days, *k* is the Monte Carlo iteration, *N* is the total number of Monte Carlo iterations, and $E_{k,d}$ is a Boolean variable describing whether there is at least one LOLH in the day:

$$E_{ki} = \begin{cases} 0\ if\ LOLH_{kd} = 0 \\ 1\ if\ LOLH_{kd} \neq 0 \end{cases}$$

Where $LOLH_{k,d}$ is the loss of load duration for a day of each iteration, the calculation equation is shown below:

$$LOLH_{kd} = \sum_{Hour\ i=1}^{H_d} B_{ki}$$

Where *i* is a variable representing each hour, B_{ki} is the Boolean variable (defined above) representing whether there is demand not supplied in hour *i,* in the *kth* iteration, and H_d is the total number of hours in the day being evaluated.

Expected Unserved Energy

EUE is the total amount expected MWh of demand that will not be served in a given period, calculated based on how much demand exceeds available capacity across all hours. As a result, EUE is an energy-centric metric that considers the magnitude and duration for all hours of the period analyzed. It is calculated in MWh. EUE is calculated in this report using the following formula:

$$EUE = \frac{1}{N}\sum_{k=1}^{N} ENS_k$$

Where ENS_k is the energy not supplied in the *kth* Monte Carlo iteration, and *N* is the total number of Monte Carlo iterations. In the results of this report, we also report the average hourly EUE whenever there is a LOLH (i.e., the average amount of MWs of capacity shortfall in the hour).

Appendix 3. Resource Adequacy – Regional Considerations

A comparison of resource adequacy approaches for various other utilities and planning entities that have similarities to Puerto Rico is provided in this appendix. Utilities and planning entities considered in this review were selected based on having similar characteristics to Puerto Rico, including other islands, similar geographic location and climate, and similar renewable integration goals.

Resource Adequacy for Other Islands

Maintaining high levels of system resource adequacy is especially challenging for islanded systems. The main reason for this is that islands are not able to import electricity from neighboring utility systems during times of peak demand and/or deficient generation capacity. In contrast, a utility on the U.S. mainland would generally be able to import electricity from neighbors when needed. In addition, many islands, including Puerto Rico, have a relatively small number of total generators available to be dispatched at any point in time. As a result, islands are often at a high risk of not being able to serve load in the event of a loss of a large generator, due to the simple fact that there is a limited number of other generators that could be dispatched to cover for the large generator's outage. In contrast, planning regions and large utilities in the U.S. mainland can have hundreds, and sometimes thousands, of other generators that could be dispatched to cover for power plant outages.

U.S. Virgin Islands

As one of Puerto Rico's island neighbors, the U.S. Virgin Islands has several similarities to Puerto Rico from a generation resource adequacy perspective. Neither can import electricity from neighbors (as would be the case on the U.S. mainland), both have similar climates, and both have similar renewable energy goals. The utility that operates the electrical system for the U.S. Virgin Islands, the Virgin Islands Water and Power Authority (VIWAPA), released an updated IRP in 2020 where they discussed several items related to the resource adequacy considerations for the Virgin Islands.[22] The IRP planning horizon spanned 2020–2044 and notes the requirement that 50 percent of electricity generation in the U.S. Virgin Islands (as a percentage of peak demand) must come from renewable resources by 2044. VIWAPA's resource adequacy planning criteria sets a loss of load target of 1 day per year in 2024, which gradually reduces to 0.10 days per year by 2044. In addition, VIWAPA has an "N-1-1" planning criterion, which requires sufficient installed generation capacity to be available during the loss of two of the largest generators, or key transmission lines.

Hawaii

From generation resource adequacy perspective, Hawaii also has several similarities with Puerto Rico. They cannot import electricity from neighbors, have similar climates, and both are undergoing the integration of more renewable resources. The Hawaiian Electric Company (HECO) operates the electrical system in Hawaii. HECO's resource adequacy considerations are summarized in a recent filing with the Hawaiian Public Utility Commission, titled the 2021 Adequacy of Supply.[23] In the filing, HECO notes some recent modifications to their resource adequacy planning criteria, namely the implementation of an ERM

[22] VIWAPA Final IRP Report, 21 July 2020.
[23] Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.

concept for the purposes of examining resource adequacy in all hours of the year. The ERM is defined as the percentage of excess system capacity over system load in each hour and accounts for Hawaii's inability to import emergency power from a neighboring utility. The ERM is rooted in HECO's guideline of requiring the system LOLE to be less than one day per 4.5 years.

The ERM concept being used by HECO includes contributions from variable renewable generators, energy storage, demand reduction programs, and other similar resources. HECO defines the dependable contributions from renewable generators to resource adequacy probabilistically, based on the following equation:

$$Dependable\ Capacity_{Hourly} = Average\ Generation_{Hourly} - N \cdot (Standard\ Deviation)$$

Here the hourly dependable capacity of the renewable generator is equal to that generator's historical production for that hour, reduced by the standard deviation of the historical production. The value of *N* is set by HECO to be 1 for wind generators and 2 for solar generators. For example, if a solar power plant on average has generated 100 MW at noon, but with a standard deviation of 20 MW, then only 60 MW would be considered as dependable capacity (100 MW – 2 x 20 MW = 60 MW) at noon.

Guam

Guam's electrical system is operated by the Guam Power Authority. As an island with a similar climate to Puerto Rico, Guam shares many similar resource adequacy challenges as Puerto Rico. Guam Power Authority is currently undertaking the process to develop an updated IRP; however, previous IRP filings note the island targets a one day per 4.5 years LOLE resource adequacy risk measure.[24] Guam Power Authority indicates that at least a 54% PRM is required to meet this level of resource adequacy. Guam Power Authority also utilizes an "N-2" planning criteria, requiring sufficient generation to cover the loss of the island's two largest generating sources.

Resource Adequacy for Other U.S. Locations Near Puerto Rico (Non-Islands)

Additional comparisons of non-island, U.S. utilities and planning regions near Puerto Rico were also developed. These are discussed below:

Florida Reliability Coordinating Council

As the closest state to Puerto Rico, Florida shares similarities to Puerto Rico in terms of climate and both solar energy potential and growth. The Florida Reliability Coordinating Council (FRCC) is a southeast U.S. regional entity responsible for assessing and ensuring reliable operation of the bulk power system, as is required by the Florida Public Services Commission. FRCC has several different member organizations, comprised of local utilities, electricity cooperatives, and other similar organizations. FRCC receives data annually from its members to develop a regional load and resource plan to produce an electricity reliability assessment report.[25] This report projects electrical system performance for the FRCC region by analyzing reserve margins, LOLP, forced outage rates, and other related items. One item that is directly applicable to Puerto Rico is FRCC's adequacy calculation, which removes the availability of firm electricity imports, or in other words, treats the region as an island for resource adequacy calculation

[24] Guam Power Authority Integrated Resource Plan, FY2013.
[25] FRCC 2021 Load & Resource Reliability Assessment Report V1, 29 July 2021.

purposes. The most recent report notes that the “islanded” system is able to meet a 0.10 days per year planning criteria, with reserve margins meeting or exceeding 20% in each year of the ten-year study.

While FRCC and its members are not islanded, electricity transfer limitations and non-import modeling scenarios are considered within their studies; however, the sheer number of generators and size of the system does inherently reduce resource adequacy vulnerabilities when compared to smaller systems, such as Puerto Rico’s.

Florida Power & Light

Within the FRCC region, Florida Power & Light conducts its own jurisdictional resource planning analysis in accordance with state policies.[26] While Florida Power & Light also plans for a resource adequacy risk target of 0.10 days/year, the utility also enforces two other resource adequacy criteria:

4. A 20% total reserve margin should exist for the summer and winter
5. At least 10% of the total reserve margin must come from centralized generators

It is important to note that there are many demand-side resources in Florida. The planning criteria above are unique in that they address the desire for diversification in how resource adequacy needs are met within Florida. These planning criteria are examples of how utilities can have unique planning criteria based on the characteristics of the specific location.

Resource Adequacy for U.S. Locations with High Solar Levels (Non-Islands)

There has been significant interest and growth in renewable energy over the recent decades both as renewable energy prices have fallen and as federal, state, and local policies have been enacted to promote the growth of renewable energy. Utilities operating within jurisdictions that enforce such policies are required to consider the contributions and impacts of higher renewable generation levels to electrical system resource adequacy. The state currently with the highest amount of installed solar generation in the U.S. is California.

California Utilities

In California, the prevailing renewable portfolio standard requires 60% of the state's electricity come from carbon-free resources by 2030, with the requirement increasing to 100% by 2045. Puerto Rico is also currently pursuing significant growth in solar generation to meet the island’s own renewable portfolio standard of 40% by 2025, 60% by 2040, and 100% by 2050. The state regulating authority establishes resource adequacy obligations for all load serving entities, including investor-owned utilities, within state jurisdiction.[27] The state resource adequacy program contains three distinct requirements:

6. Load serving entities are required to meet a 15% PRM on top of their approved load forecast.
7. Each local area must have sufficient capacity to meet energy needs for a 1-in-10 worst weather scenario and an N-1-1 contingency event (e.g., the loss of the two largest generators).

[26] Florida Power & Light Company, Ten Year Power Plant Site Plan 2020-2029.
[27] California Public Utilities Commission, 2020 Resource Adequacy Report.

8. Load serving entities are required to procure “flexible capacity”, or capacity that can quickly be dispatched and ramped to full power. Specifically, enough flexible capacity must be procured to meet the largest three-hour ramp in system load (defined on a monthly basis). The reason for this resource adequacy requirement stems from the fact that there is a significant amount of intermittent generation (i.e., solar energy) installed in the California. As a result, the California electrical system can sometimes see sharp swings in supplied generation if clouds quickly appear, during sunsets, etc. Examples of flexible capacity include dispatchable resources such as energy storage, fast ramping thermal units (such as engines, combustion turbines, combined cycles), etc.

The California Public Utilities Commission performs detailed analyses to determine the amount a generator’s capacity is able to contribute toward resource adequacy requirements, which is also known as a generator’s effective load carrying capability (ELCC).[28] The ELCC of a generator is defined by how much system loads can increase when the generator is added into the electrical system, with equivalent performance in terms of system resource adequacy. In California, the ELCC calculation is based on an enforcement of both 0.10 days/year and 0.02-0.03 days/month LOLE targets.[29]

The ELCC of a generator varies by technology type and the capability of the generator to contribute towards serving load when generation is needed most. For example, if generation were needed to meet a load peak in the evening, a stand-alone solar power plant is likely to have a lower ELCC than a solar power plant paired with an energy storage system, due simply to the fact that the stand-alone solar power plant would not be capable of generating much electricity in the evening (since the sun would have nearly set at this time), while the storage system tied to the other solar power plant likely could generate some electricity in the evening. ELCC will vary from one planning region to another because load characteristics change from region to region; for example, the ELCC values calculated for California’s generators would not be directly applicable to values calculated for Puerto Rico.

High-Level Comparison by Location

The following table compares the key resource adequacy considerations for various locations, including the location-specific resource adequacy risk measures that are followed. The column for the “Target Adequacy Risk Measures” are the target amounts of loss of load that each utility / planning entity strives to meet. For example, a value of “1 day per 10 years” means that the utility strives to have a system resource adequacy level such that on average there is only one day where load cannot be fully served every ten years.

[28] Incremental ELCC Study for Mid-Term Reliability Procurement. August 31, 2021.
[29] Loss of Load Expectation, Effective Load Carrying Capability, and Planning Reserve Margin Studies for 2024.

Table A-2: High-Level Resource Adequacy Comparison by Location

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or Similar Values)	Notes
Virgin Islands Water and Power Authority	2020: 1 day per year Reducing to, 2044: 1 day per 10 years	U.S. territory islands neighboring Puerto Rico, similar climate and lack of electricity import ability. Additional N-1-1 planning criterion requires sufficient installed capacity to cover loss of two largest resources. Target LOLE is a recent 2024 goal set forth in the 2019 IRP.[1]
Hawaiian Electric Company	Energy Reserve Margin, based on the following: 1 day per 4.5 years	U.S island with similar load profile, generation, climate, and inability to import electricity as exists in Puerto Rico. HECO bases their resource adequacy criteria on a one day per 4.5 years guideline for assessing resource adequacy. This LOLE target helps to inform the Energy Reserve Margin planning criteria, which is the percentage by which the system capacity must exceed the system load in each hour, considering all generation and load reduction sources, including renewable and storage resources (Hawaii's previous planning criteria did not account for the contributions made by renewable generators).[2]
Guam Power Authority	1 day per 4.5 years	U.S. territory island with similarities to Puerto Rico in terms of climate, and lack of electricity import ability. The Guam Power Authority requires a minimum reserve margin of 54%. Guam currently has a reserve margin over 100% of its peak load.[3]
Florida Reliability Coordinating Council	1 day per 10 years	Florida has a similar climate to Puerto Rico, and similar probability of hurricane events. Florida's LOLE performance is measured under various system conditions, including zero import availability, and varying solar generation levels. Aggressive solar integration targets 30 million solar panels installed by 2030.[4]
Florida Power & Light	1 day per 10 years	Florida Power & Light is a vertically integrated utility located in the southeast U.S. In addition to the 1 day in 10 years LOLP planning criterion, Florida Power & Light maintains 10% generation-only PRM criterion and a 20% total PRM criterion (including other resources, i.e., demand side-reduction, etc.) for summer and winter seasons.[5]
Southern California Edison	1 day per 10 years 0.02-0.03 days per month	Southern California Edison's Integrated Resource Plan studied a 0.1 days per year LOLE standard and considers the latest renewable and environmental/emissions targets. Results showed a need to increase the PRM to 16.5% (from 15%) in 2024 and 17.5% in 2026 to maintain the traditional 0.1 days per year LOLE standard.[6]
Arizona Public Services Company	24 hours over 10 years	Arizona Public Services Company is a utility in the Western Electricity Coordinating Council and has a 100% clean energy goal for 2050 that includes carbon-free resources like solar, wind, demand-side management, and nuclear. As part of the 2030 interim clean energy goal, a 45% requirement for renewable generation is required. Results from Arizona Public Services' 2020 IRP Reserve Margin Study indicate a 15% reserve margin is sufficient to meet the company's resource adequacy requirements.[7]
Tucson Electric Power (Arizona)	15% Planning Reserve Margin	Tucson Electric Power is a utility in the desert southwest region with similar solar potential to that of Puerto Rico. The utility follows a 15% planning reserve margin guideline, supported by various probabilistic analyses. The referenced IRP investigates numerous renewable penetration levels, and the utility has a carbon reduction target of 80% by 2035. The IRP investigates the ramping capabilities / needs of generation to support renewable growth in the electrical system.[8]

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or Similar Values)	Notes
Public Service Company of New Mexico	2 days per 10 years	New Mexico has a strong solar potential and a similar load curve to that of Puerto Rico. The Public Service Company of New Mexico IRP is driven by 100% emissions free goal by 2040. It also lists its goal to transition to the industry standard LOLE of 0.1 days per year.[9]
Puget Sound Energy	LOLP of 5% per year	Puget Sound Energy is required by state law to ensure 80 percent of electric sales are met by non-emitting/renewable resources by 2030, and 100 percent by 2045. Puget Sound Energy uses a resource adequacy model to calculate various resource adequacy risk measures that quantify the risk of not serving load, establish peak load planning standards, and quantify the peak capacity contribution of renewable resources.[10]

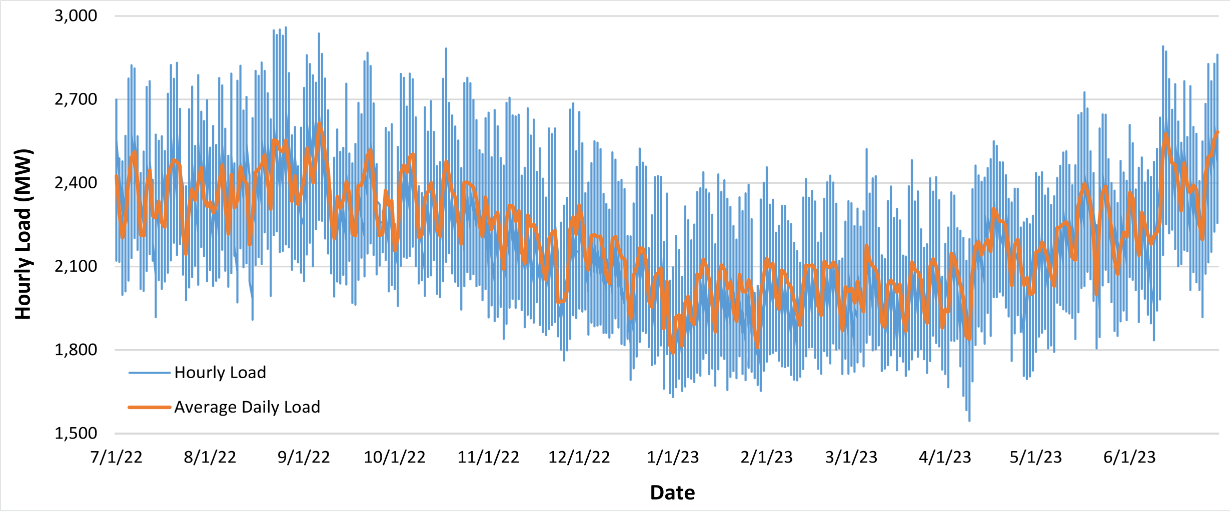
Sources

- VIWAPA Final IRP Report, 21 July 2020.
- Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.
- Guam Power Authority Integrated Resource Plan, FY2013.
- FRCC 2021 Load & Resource Reliability Assessment Report V1, 29 July 2021.
- Florida Power & Light Company, Ten Year Power Plant Site Plan 2020-2029.
- Southern California Edison Integrated Resource Plan, September 2021.
- Arizona Public Services Company, 2020 Integrated Resource Plan, 26 June 2020.
- Tucson Electric Power Company Arizona Public Services Company, 2020 Integrated Resource Plan, 26 June 2020.
- Public Service of New Mexico Integrated Resource Plan, 2021
- Puget Sound Integrated Resource Plan, April 2021.

Appendix 4. Model Inputs – System Load

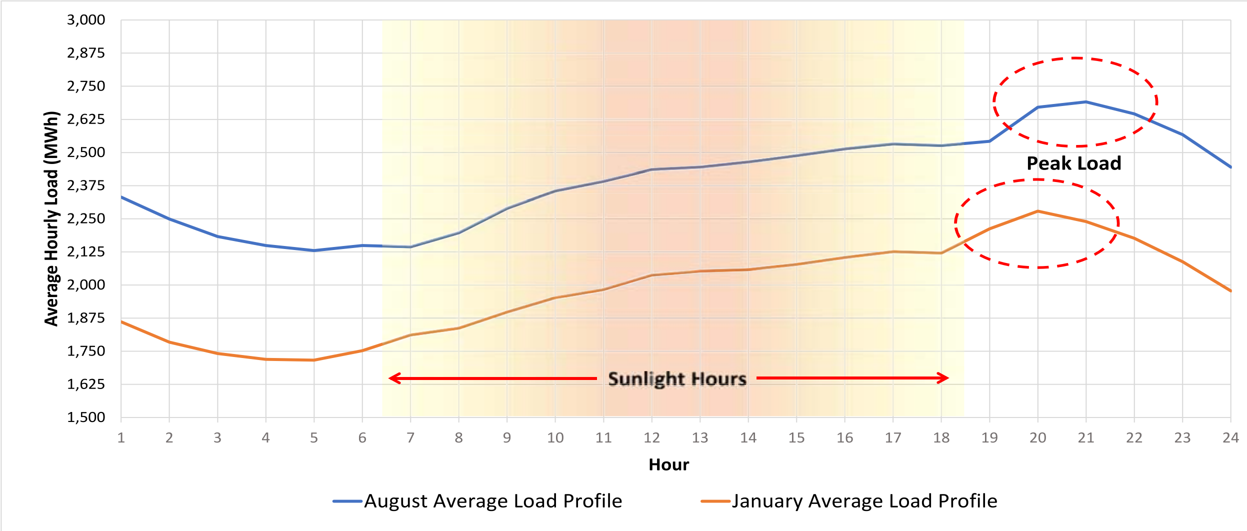
A fundamental parameter for resource adequacy modeling is system load. The FY2023 load profile that was used for these studies is shown in the figure below. This load profile was developed based on the hourly load profile for 2021 and estimated FY2023 monthly load forecasts for the different customer classes of Puerto Rico (residential, commercial, industrial, agriculture, etc.). As expected, seasonal variations are observed with total monthly demand averaging between 1,350 to 1,550 GWh in the winter months, up to near 1,800 GWh in the summer months. Peak demand is observed in August and is estimated to be 2,960 MW. Similarly, hourly variations throughout the day are observed in the load profile.

Figure A-1: Forecasted FY2023 Electrical Load Profile for Puerto Rico



The following figure shows the average hourly load for August 2022 and January 2023. Electric demand rises in the day with commercial/industrial activity and peaks in the evening, driven by residential activity.

Figure A-2: Forecasted FY2023 Electrical Load Profile – Hourly Averages



Appendix 5. Model Inputs – Generation Fleet

The characteristics of the Puerto Rican generation fleet (both thermal and renewable generators) also are very important inputs into the resource adequacy calculations. Table A-3 shows the thermal generators that were included in all three studies. The table shows when the power plants began operations, fuel consumed, nameplate capacity, expected available capacity for FY2023, and the expected forced outage rates based on historical operation. The information provides indications of a distressed system with many generators that are unreliable. For the studies, each occurrence of a forced outage was assumed to require a repair time of 40 hours.

Table A-3: Summary of Expected Operating Thermal Generators, FY2023

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Historic Forced Outage Rate (%)
AES 1	2002	Coal	227	227	3
AES 2	2002	Coal	227	227	3
Aguirre Combined Cycle 1[1]	1977	Diesel	296	220	40
Aguirre Combined Cycle 2[1]	1977	Diesel	296	100	30
Aguirre Steam 1	1971	Bunker	450	370	10
Aguirre Steam 2	1971	Bunker	450	350	10
Costa Sur 5	1972	Natural Gas	410	350	10
Costa Sur 6	1973	Natural Gas	410	350	15
EcoEléctrica	1999	Natural Gas	530	530	2
Palo Seco 3	1968	Bunker	216	190	15
Palo Seco 4	1968	Bunker	216	160	15
San Juan 7	1965	Bunker	100	70	30
San Juan 9	1968	Bunker	100	95	10
San Juan Combined Cycle 5	2008	Diesel / Natural Gas	220	200	7
San Juan Combined Cycle 6	2008	Diesel / Natural Gas	220	200	7
Cambalache 2	1998	Diesel	82.5	76	10
Cambalache 3	1998	Diesel	82.5	75	10
Mayagüez 1[2]	2009	Diesel	55	50	30
Mayagüez 2	2009	Diesel	55	50	30
Mayagüez 3	2009	Diesel	55	50	30
Mayagüez 4	2009	Diesel	55	50	30
Palo Seco Mobile Pack 1-3[3]	2021	Diesel	27 each (81 total)	81	9
7 Gas Turbines (Peakers)[4]	1972	Diesel	21 each (147 total)	147	40
Total			**4,981**	**4,218**	—

Notes:

1. The steam cycle on both the Aguirre Combined Cycle power plants are currently inoperable, repair timing is uncertain
2. Mayagüez 1 is currently out of service but is expected come back into service sometime in 2022. This analysis considers it will come back into service on January 1, 2023.
3. The Palo Seco Mobile Pack units are expected to return to service sometime in 2022. This analysis considers they will come back into service on January 1, 2023.
4. A total of 18 gas turbines, each with a capacity of 21 MW, are installed. Only 7 are considered to be operational

Table A-4 shows the renewable generators that were included in these studies along with their nameplate and available capacities, which for the renewable generators are equal because there are no derates on these generators. The existing renewable generators make up approximately 5% of the system's available capacity. Due to the intermittency of renewable generation and their low-capacity factors, forced outages for these generators have been set to zero for the resource adequacy analyses.

Table A-4: Summary of Operating Renewable Generators

Generator Name	Start of Operations	Fuel	Nameplate / Available Capacity (MW)
AES Ilumina	2012	Sun	20
Fonroche Humacao	2016	Sun	40
Horizon Energy	2016	Sun	10
Yarotek (Oriana)	2016	Sun	45
San Fermin Solar	2015	Sun	20
Windmar (Cantera Martino)	2011	Sun	2.1
Windmar (Vista Alegre / Coto Laurel)	2016	Sun	10
Pattern (Santa Isabel)	2012	Wind	75
Fajardo Landfill Tech	2016	Methane Gas	2.4
Tao Baja Landfill Tech	2016	Methane Gas	2.4
Total			**226.9**

Since renewable generators can have periods of intermittent electricity production, it was important to determine the amount of hourly renewable generation that could reliably be considered as available to serve load from a resource adequacy perspective. The methodology used in these analyses shares similarities to the methodology employed by HECO and in California. For these analyses, actual historical generation data from each of the renewable power plants was analyzed. From there, each generator's 90th percentile lowest production level for each hour was identified. To capture the fact that renewable generators are able to produce more electricity in some months than others (i.e., solar generation is typically higher in the summer months), two different 90th percentile generation levels were identified for each month, one for the first half of the month and one for the second half of the month. This methodology captured the contributions of the renewable generators to improving system resource

adequacy from a statistical framework, accounting for the intermittency of the generators. It was also fundamentally based on the actual historical production levels of the existing renewable generators.

The following table shows the estimated amount of generation that is installed BTM across the different regions of Puerto Rico (as of Q1 2022). BTM generation is broken down between resources connected to the distribution system and resources connected to the transmission system; both of which are primarily composed of rooftop solar.

These BTM resources are considered in the analysis as reductions in system load.

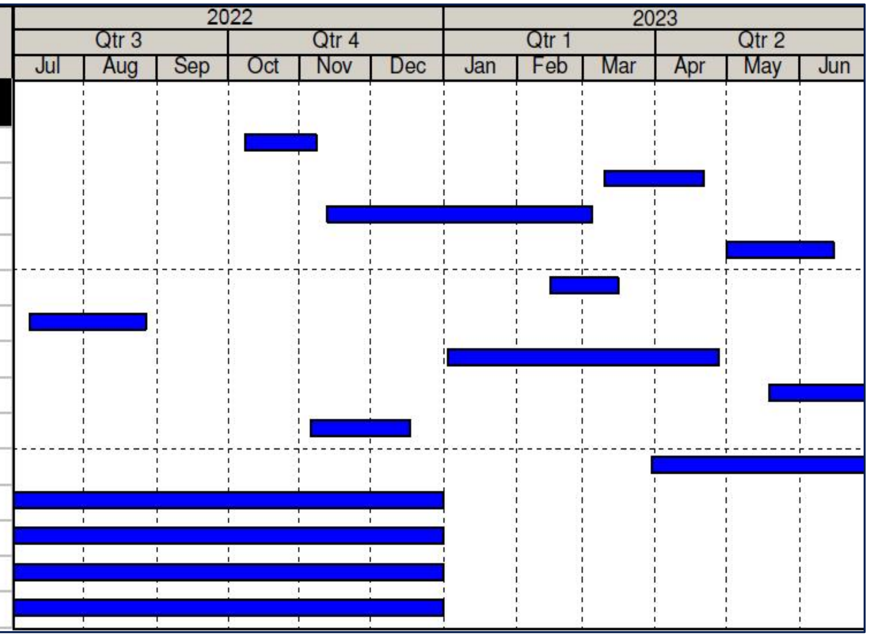
Table A-5: Summary of BTM Generation by Area

Area	BTM Generation Connected to the Distribution System (MW)	BTM Generation Connected to the Transmission System (MW)
Arecibo	25	7
Bayamon	60	12
Caguas	47	14
Carolina	33	9
Mayaguez	31	2
Ponce East	15	10
Ponce West	36	6
San Juan	119	30
Total	**366**	**90**

The following figure shows when the thermal units are expected to be out of operation, either due to planned regular maintenance or because of extended repairs (Mayaguez 1 and the Palo Seco Mobile Packs 1-3). The units are shown in order of decreasing available capacity. Note that the figure only includes generators for which any type of maintenance is planned or known. Any other capacity limitations due to forced outages would be in addition to these outage MW.

Figure A-3: Planned Maintenance Outages for Thermal Units in FY2023

Generator	Available Capacity (MW)	Maintenance Duration (Days)	Start	Finish
FY2023 Maintenance				
EcoElectrica	530	31d	08-Oct-22	07-Nov-22
Aguirre Steam 2	350	43d	10-Mar-23	21-Apr-23
Costa Sur 5	350	113d	12-Nov-22	04-Mar-23
Costa Sur 6	350	46d	01-May-23	15-Jun-23
AES 1	227	29d	15-Feb-23	15-Mar-23
AES 2	227	50d	09-Jul-22	27-Aug-22
Palo Seco 3	190	116d	02-Jan-23	27-Apr-23
Palo Seco 4	160	43d	19-May-23	30-Jun-23
San Juan 9	95	43d	05-Nov-22	17-Dec-22
San Juan 7	70	93d	30-Mar-23	30-Jun-23
Mayaguez 1	50	184d	01-Jul-22	31-Dec-22
Palo Seco Mobile Pack 1	27	184d	01-Jul-22	31-Dec-22
Palo Seco Mobile Pack 2	27	184d	01-Jul-22	31-Dec-22
Palo Seco Mobile Pack 3	27	184d	01-Jul-22	31-Dec-22

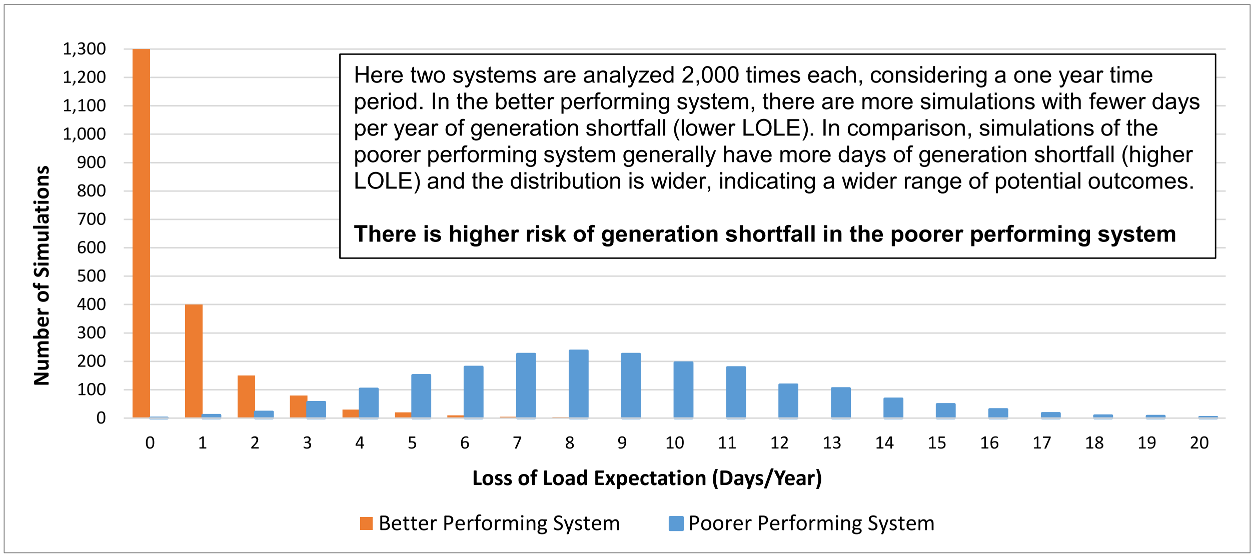


Appendix 6. Resource Adequacy Modeling Introduction

The fundamental calculation at the center of resource adequacy modeling is determining the total amount of generation capacity that is available and comparing it to system load. For each simulated scenario, the total capacity available to serve system load is determined for each hour of the simulated year, then each simulation is re-run many times to account for different forced outage timing. Available capacity is the sum of available thermal, renewable, and energy storage capacity (based on the storage charge level). The output of the simulations is a statistical distribution of simulation results that help to inform the risk associated with generation shortfall in the future.

An example figure below helps to illustrate sample results of resource adequacy simulations. The figure presents the distribution of LOLE output for two systems that are simulated 2,000 times each. As can be seen, the better performing system has more simulations with lower LOLE than the poorer performing system.

Figure A-4: Example Systems LOLE Distribution Comparison



The key inputs associated with the model are described as follows.

System Load

The load profile was developed based on the hourly load profile for 2021 and estimated FY2023 monthly load forecasts for the different customer classes of Puerto Rico (residential, commercial, Industrial, agriculture, etc.). Section Appendix 4 discusses the system load input in detail.

Thermal Generation Inputs

- **Generator available capacity.** The net capacity of the thermal generator (nameplate capacity minus any derates) defines the capacity contribution of the thermal generator when it is available to serve load, i.e., when the generator is not in either a planned or forced outage.
- **Generator planned outage schedule.** This input defines when the thermal generator is expected to be out on a planned maintenance outage. The schedule is taken from the LUMA operations from Q2 2022.
- **Generator forced outage rate.** The forced outage rate is based on historical forced rates of the thermal generators dating back 5 years. The forced outage rate defines how frequently a power plant breaks down during the simulation. The timing of forced outage events is random in the simulation.
- **Generator forced outage duration.** This input defines how long it takes a thermal power plant to come back online after a forced outage. For this analysis the forced outage duration is set to 40 hours.

Renewable Generation Inputs and Methodology

- **Historical Hourly Renewable Generation.** The simulated generation associated with the existing renewable power plants is based on historical operating data from the power plants. From a resource adequacy perspective, it was important to determine the amount of renewable generation that could reliably be counted on as available to serve load. The methodology used in this analysis to determine the reliable contribution of the renewable power plants shares many similarities to the methodology employed by HECO and in California. For this analysis, each power plant's historical 90th percentile lowest production level for each hour was identified. To capture the fact that renewable generators are able to produce more electricity in some months than others (i.e., solar generation is typically higher in the summer months), two different 90th percentile generation levels were identified for each month, one for the first half of the month and one for the second half of the month. These profiles were used in the analysis.
- **Forecasted Hourly Renewable Generation Production.** For future renewable generators, forecasted hourly generation is computed based on the available renewable resource in Puerto Rico. The hourly profile of the forecasted renewable generation is determined using PVsyst, a solar PV production estimation tool. Satellite-based solar resource profiles for the specific project locations are input into PVsyst in order to determine the hourly generation forecast. The hourly profiles consider both hour-by-hour and day-to-day production differences due to variables such as cloud cover, weather, etc. All forecasted hourly profiles are adjusted to a P90 probabilistic level prior to performing the simulations. A P90 level is used as this was assumed to be the production level that could reliably be counted on to serve system load from a resource adequacy perspective. The P90 to P50 ratio considered for this analysis was 89.8%.

Energy Storage Inputs

Energy storage is considered in the model in two forms: standalone energy storage and solar-paired energy storage. For both types of storage, the normal (non-emergency) discharge time is set to start in the evening, coinciding with peak load. The energy storage is modeled to inject all of its stored energy to meet peak load through evening. In the event that an emergency event occurs, defined as a time when load exceeds available capacity, the energy storage resources are modeled such that they inject stored

energy up to their nameplate capacity to either meet the system generation shortfall, or if the generation shortfall is too great, minimize the magnitude of the shortfall. Once the amount of stored energy is depleted, the modeled energy storage is unable to inject additional energy. During an emergency event, the energy storage is modeled to inject its storage energy regardless of the time of day or how much energy is stored at that time. All storage is modeled as having an 85% round-trip efficiency. Specific details regarding standalone and solar-paired energy storage are provided below.

- **Standalone Energy Storage.** Standalone energy storage resources are modeled as being able to charge via the grid, with the freedom to charge from any type of generation resource. These resources are modeled such that charging is allowed to start in the early morning (i.e., around midnight), so long as there is excess generation capacity available during that time.
- **Energy Storage Paired with Solar PV.** These storage resources are modeled similarly to standalone energy storage, with the caveat that solar-paired storage can only charge from available solar PV generation. As such, storage paired to solar PV begins charging as the sun rises around 7 a.m. and is able to continue to charge through the day until sunset.

Appendix 7. Resource Adequacy Model Validation

Resource adequacy analyses of the Puerto Rican electric system were performed using both a PROMOD model adapted for resource adequacy calculations (PROMOD is a generator and electric portfolio simulation software maintained by Hitachi Energy) and the PRAS model, a probabilistic resource adequacy simulation tool adapted for the Puerto Rican electrical system.

Model Validation

As part of model validation, a thorough benchmarking / error checking process was undertaken to verify simulation output. The validation process consisted of independently simulating the current Puerto Rican electrical system for FY2023 with three different tools: PROMOD, PLEXOS, and the PRAS model. PLEXOS is an industry-accepted market simulation software owned by Energy Exemplar that is also capable of performing resource adequacy calculations.

The following table compares the output for LOLE and LOLH between the PRAS model, PROMOD, and PLEXOS. Note that 2,000 simulations were performed using the PRAS model, while 200 were performed using PROMOD and PLEXOS. This is because both PROMOD and PLEXOS take much longer to solve than the PRAS model (the PRAS model has approximately a 20x faster convergence time). The additional simulations that were able to be performed with the PRAS model allow for a stronger statistical confidence level in solution output. As can be seen in the table below, there is strong agreement between the three tools.

Table A-6: Loss of Load Expectation Validation Summary Statistics

Measure	PRAS Model	PROMOD	PLEXOS
Average (Days / Year)	8.81	8.43	8.19
Standard Deviation (Days / Year)	3.46	2.99	2.74
Maximum (Days / Year)	24	19	16
Number of Iterations Performed	2,000	200	200

Table A-7: Loss of Load Hours Validation Summary Statistics

Measure	PRAS Model	PROMOD	PLEXOS
Average (Hours / Year)	40.77	39.48	37.73
Standard Deviation (Hours / Year)	21.69	21.32	19.51
Maximum (Hours / Year)	146	113	86
Number of Iterations Performed	2,000	200	200

Looking further into the comparison of LOLH, the timing of LOLH from both an hourly and monthly perspective were compared. The next two figures provide this comparison. As can be seen, there is generally close agreement in LOLH timing for all three tools.

Figure A-5: Loss of Load Hours Broken Out by Hour of the Day for Tool Validation

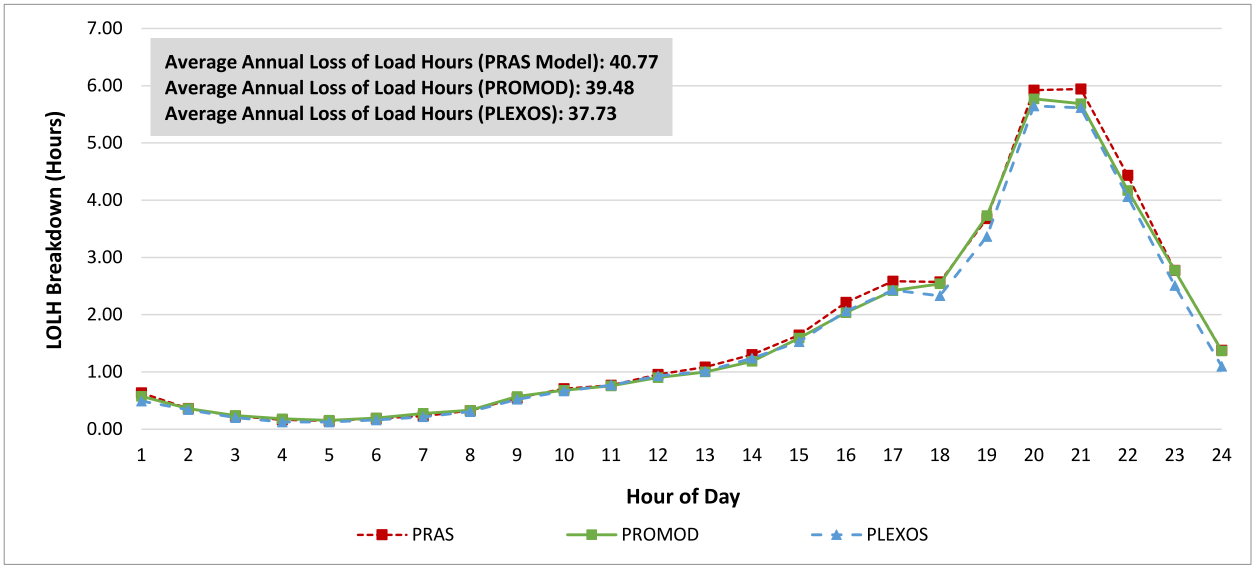
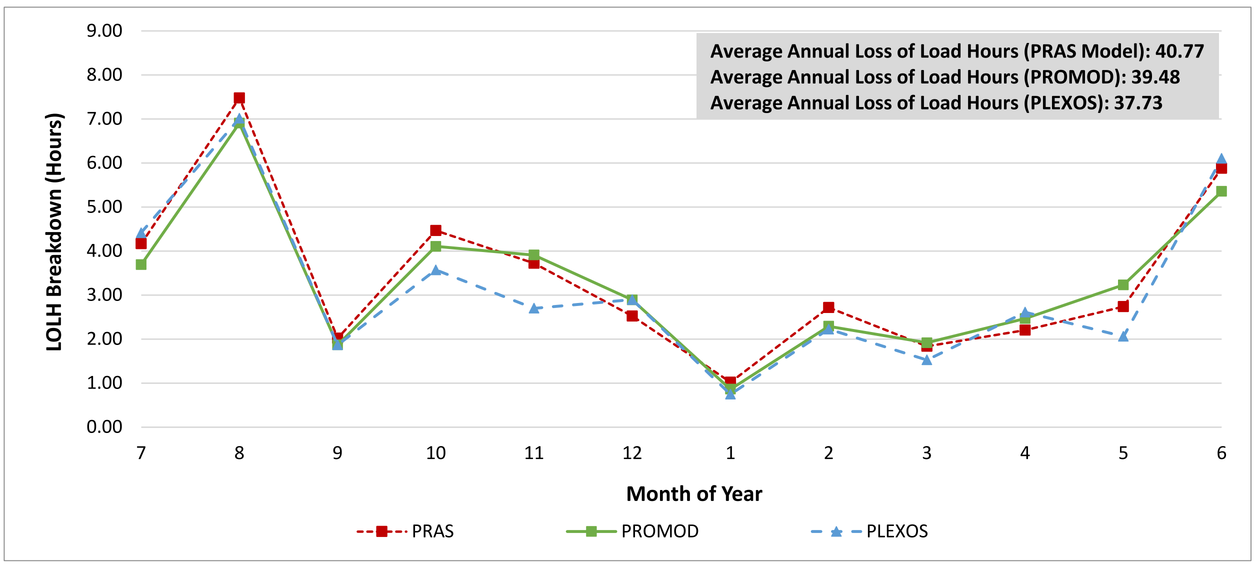


Figure A-6: Loss of Load Hours Broken Out by Month of the Year for Tool Validation



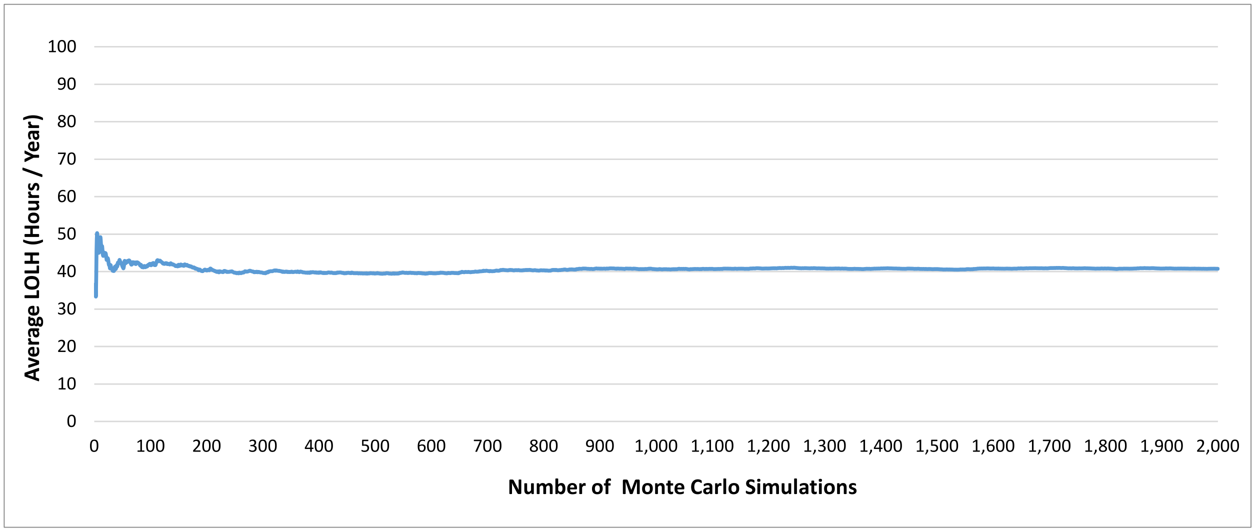
The results of the validation process indicated that output was consistent between the three different tools. The PRAS model had the additional benefit of significantly faster runtimes. For this reason, the PRAS model was used as the primary tool for the various sensitivity analyses described in this report.

Model Convergence

The following figures help to illustrate the convergence of the PRAS model calculation process. In the first figure, the x-axis represents the number of simulations performed, and the y-axis represents the average number of LOLH calculated based on the number of simulations performed. For example, the figure indicates that the average LOLH at 500 simulations was approximately 40 LOLH, meaning the average

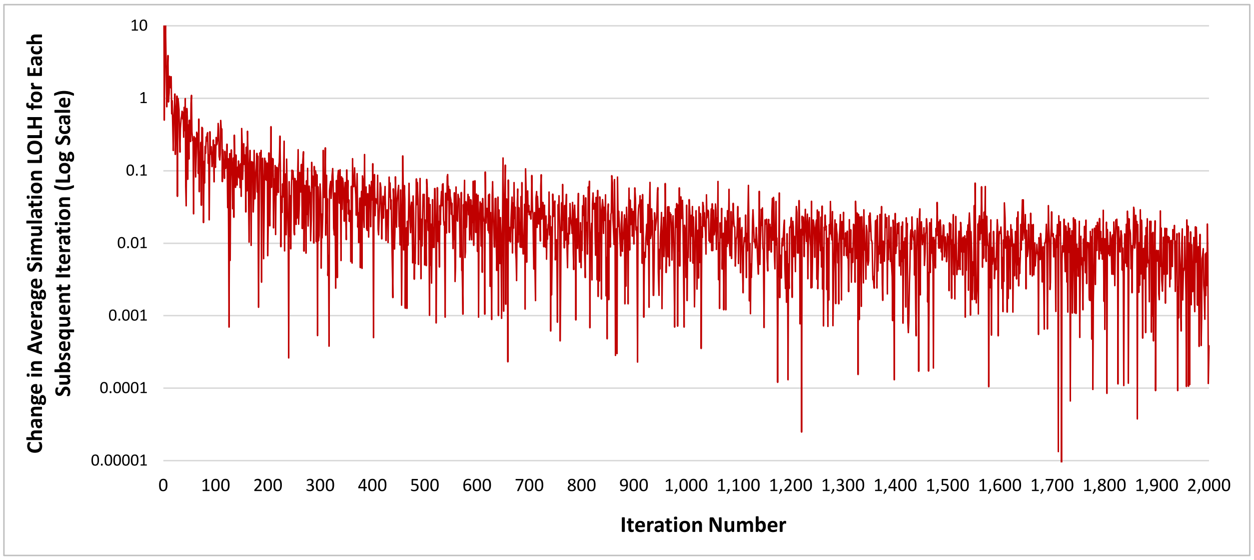
number of annual LOLH for simulation numbers 1 through 500 was approximately 40 LOLH. As can be seen in the plot, the solution starts to converge relatively quickly in the calculation process.

Figure A-7: Average Simulation LOLH per Subsequent Iterations



The figure below illustrates the average LOLH for all completed simulations as a function of each subsequent iteration. Results are presented on a logarithmic scale y-axis. As can be seen in the plot, the change in average LOLH falls below 0.1 LOLH approximately 500 iterations into the simulation. At that point, results were considered to be generally converged; however, an additional 1,500 simulations were completed to further validate convergence. All results from the PRAS model presented in this report performed 2,000 iterations.

Figure A-8: Change in Simulation LOLH per Subsequent Iterations (Log Scale)



Appendix 8. Forced Outage Rates – PREPA Units

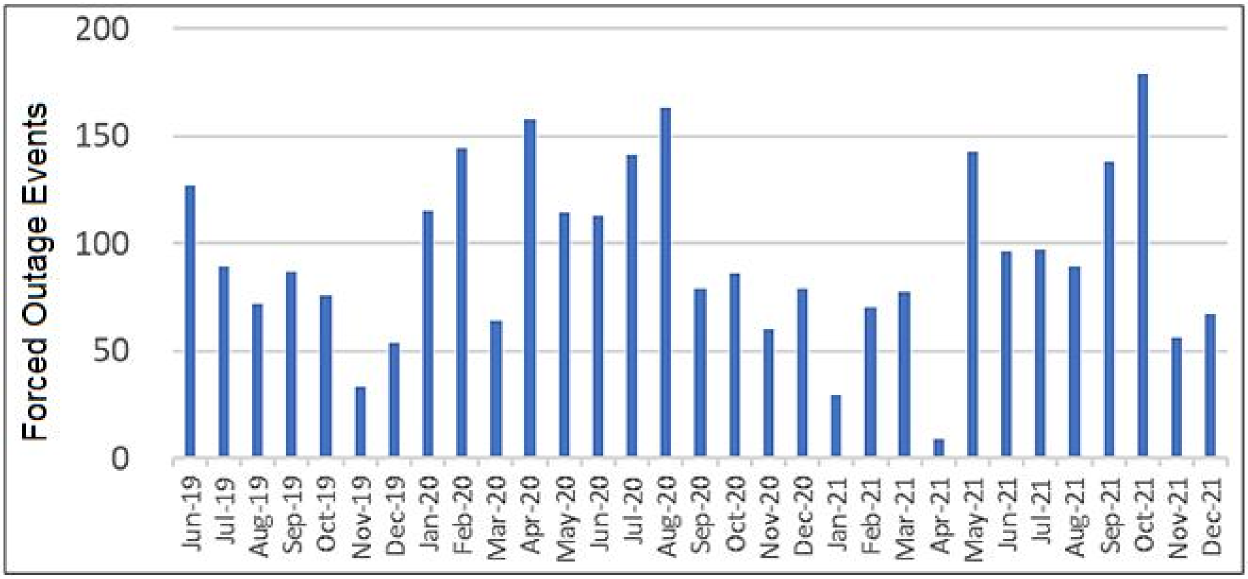
From a resource adequacy perspective, the generation portfolio in Puerto Rico raises several modeling challenges. While the AES and EcoEléctrica power plants exhibit very strong performance on forced outage rates with annual rates of approximately 3% and 2%, respectively (which are consistent or slightly better than industry averages for comparable units), the PREPA generation plants have, for various reasons, historical forced outage rates of approximately 11% for baseload and 32% for peaker plants (which is significantly higher than industry averages).

The Puerto Rico generation portfolio is dominated by its relatively high concentration of larger units. There are six units that are over 400 MW nameplate capacity, and another eight that are over 200 MW capacity. What this means is if one of the larger units has a forced outage, the grid loses approximately 15% of its operating capacity at any given time. This is a significantly large amount of generation capacity to lose from a portfolio risk perspective. In most ISOs in North America, if they lose even a large 1,000 MW nuclear plant, there is minimal impact to the entire grid because that represents only one or two percent of total operating capacity. In addition, being an island with no interconnecting transmission lines to neighboring utilities, the resource adequacy analysis is much more sensitive to the selection of the appropriate forced outage rate than would be seen in most utilities in the mainland and around the world.

Most utilities plan for an N-1 planning standard so that if one significant event occurs (e.g., loss of generator or major transmission line), service to customers is not interrupted. These types of events are not significant in the mainland since there is always a high likelihood that neighboring capacity that can be acquired at some price. In Puerto Rico, the modeling assumptions have to recognize that first, there is a higher probability of losing a major unit and thus 15% of generating capacity, and secondly, losing that first unit also increases the probability of causing the loss of a second unit due to the additional stresses put on the remaining power plants due to low reserve margins.[30] This is illustrated in Figure A-9, which shows that the forced outage rate during summer months when reserves are low is almost twice the forced outage rate of the rest of the year.

[30] For modeling purposes in this analysis, a forced outage event to a generator is treated as an independent event, unrelated to other forced outages on the system. Future iterations of this analysis might consider whether correlations between forced outages might be incorporated.

Figure A-9: Total Forced Outage Events, All PREPA Units – June 2019–December 2021



To apply the appropriate forced outage rates for this resource adequacy analysis, LUMA considered the historical forced outage rates over the past nine years, but primarily focused on the most recent data since June 2019. LUMA evaluated each unit and considered the average forced outage rates for the most recent six months, year, and past three years to determine the appropriate rate by generator. In some cases, poor performance was not weighted as heavily if it occurred two or three years ago and demonstrated improvement since then. LUMA considered the forced outage rate for each plant and identified a revised forced outage rate for each unit. The forced outage rates assumed for resource adequacy modeling are summarized in the table below and the supporting analysis for each unit in the PREPA portfolio is discussed in the pages that follow in this appendix.

Table A-8: Summary of Expected Operating Thermal Generators in FY2023

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Historic Forced Outage Rate (%)
AES 1	2002	Coal	227	227	3
AES 2	2002	Coal	227	227	3
Aguirre Combined Cycle 11	1977	Diesel	296	220	40
Aguirre Combined Cycle 21	1977	Diesel	296	100	30
Aguirre Steam 1	1971	Bunker	450	370	10
Aguirre Steam 2	1971	Bunker	450	350	10
Costa Sur 5	1972	Natural Gas	410	350	10
Costa Sur 6	1973	Natural Gas	410	350	15
EcoEléctrica	1999	Natural Gas	530	530	2
Palo Seco 3	1968	Bunker	216	190	15

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Historic Forced Outage Rate (%)
Palo Seco 4	1968	Bunker	216	160	15
San Juan 7	1965	Bunker	100	70	30
San Juan 9	1968	Bunker	100	95	10
San Juan Combined Cycle 5	2008	Diesel / Natural Gas	220	200	7
San Juan Combined Cycle 6	2008	Diesel / Natural Gas	220	200	7
Cambalache 2	1998	Diesel	82.5	76	10
Cambalache 3	1998	Diesel	82.5	75	10
Mayagüez 12	2009	Diesel	55	50	30
Mayagüez 2	2009	Diesel	55	50	30
Mayagüez 3	2009	Diesel	55	50	30
Mayagüez 4	2009	Diesel	55	50	30
Palo Seco Mobile Pack 1-33	2021	Diesel	27 each (81 total)	81	9
7 Gas Turbines (Peakers)4	1972	Diesel	21 each (147 total)	147	40
Total			**4,981**	**4,218**	—

Notes:

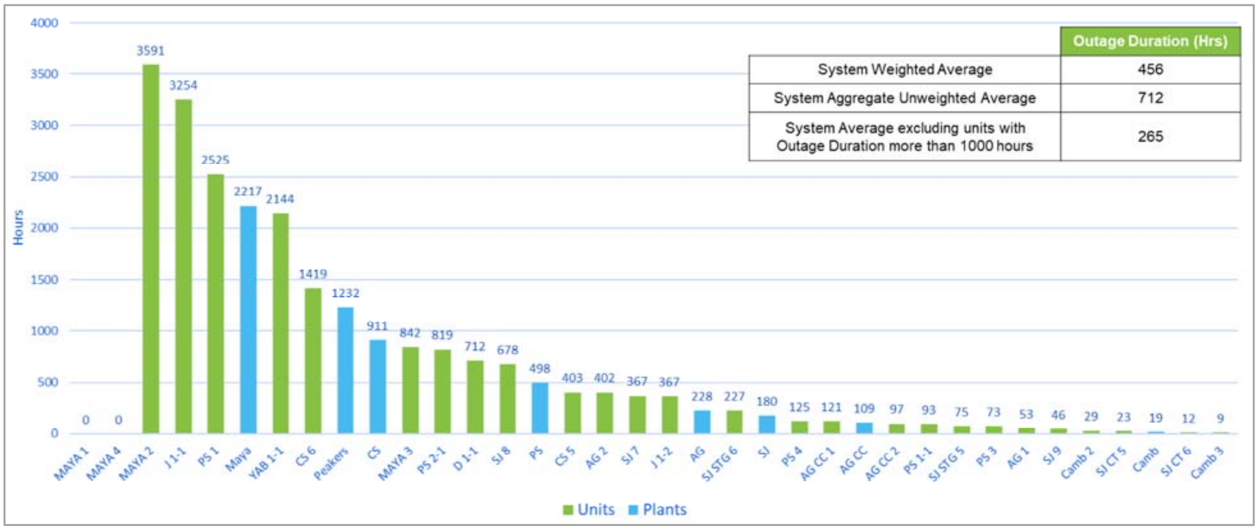
1. The steam cycle on both Aguirre Combined Cycle power plants is currently inoperable. Repair timing is uncertain.
2. Mayagüez 1 is currently out of service but is expected come back into service sometime in 2022. This analysis considers it will come back into service on January 1, 2023.
3. The Palo Seco Mobile Pack units are expected to return to service sometime in 2022. This analysis considers they will come back into service on January 1, 2023.
4. A total of 18 gas turbines, each with a capacity of 21 MW, are installed. Only 7 are considered to be operational.

Table A-9: Forced Outage Rate Information

Generator Type	Generator	2021 Inputs	Updated Input: All Cases
Thermal	AES_1	3.00%	3%
Thermal	AES_2	3.00%	3%
Thermal	Aguirre 1 CC	8.78%	40%
Thermal	Aguirre 2 CC	2.00%	30%
Thermal	Aguirre ST_1	6.28%	10%
Thermal	Aguirre ST_2	2.29%	10%
Thermal	Cambalache CT_2	9.60%	10%

Generator Type	Generator	2021 Inputs	Updated Input: All Cases
Thermal	Cambalache CT_3	1.20%	10%
Thermal	Costa Sur 5	12.04%	10%
Thermal	Costa Sur 6	2.89%	15%
Thermal	Palo Seco 1	42.69%	20%
Thermal	Palo Seco 3	4.91%	15%
Thermal	Palo Seco 4	9.96%	15%
Thermal	San Juan 7	22.77%	30%
Thermal	San Juan 8	30.75%	30%
Thermal	San Juan 9	10.34%	10%
Thermal	San Juan 5 CC NG Conversion	5.39%	7%
Thermal	San Juan 6 CC NG Conversion	7.45%	7%
Thermal	Mayagüez GT 1	10.16%	30%
Thermal	Mayagüez GT 2	33.77%	30%
Thermal	Mayagüez GT 3	5.08%	30%
Thermal	EcoEléctrica	1.00%	2%
Peaker	GT01 – Palo Seco	24.00%	40%
Peaker	GT02 – Palo Seco	24.00%	40%
Peaker	GT10 – Aguirre	24.00%	40%
Peaker	GT11 – Yabucoa	24.00%	40%
Peaker	GT14 – Vega Baja	24.00%	40%
Peaker	GT19 – Jobos	24.00%	40%
Peaker	GT20 – Jobos	24.00%	40%
Peaker	GT21 – Daguao	24.00%	40%
Peaker	GT22 – Daguao	24.00%	40%
Renewable	Hydro Yauco 1	1.00%	1%
Peaker	Palo Seco Mobile Pack 1	9.00%	9%
Peaker	Palo Seco Mobile Pack 2	9.00%	9%
Peaker	Palo Seco Mobile Pack 3	9.00%	9%

Figure A-10: Average Forced Outage Duration – June 2019–December 2021



Mayagüez 1 and 4 have no reported forced outage occurrences even though they have over 8,000 and 5,000 forced outage hours, respectively.

Figure A-11: Average Forced Outage Rate – June 2019–December 2021

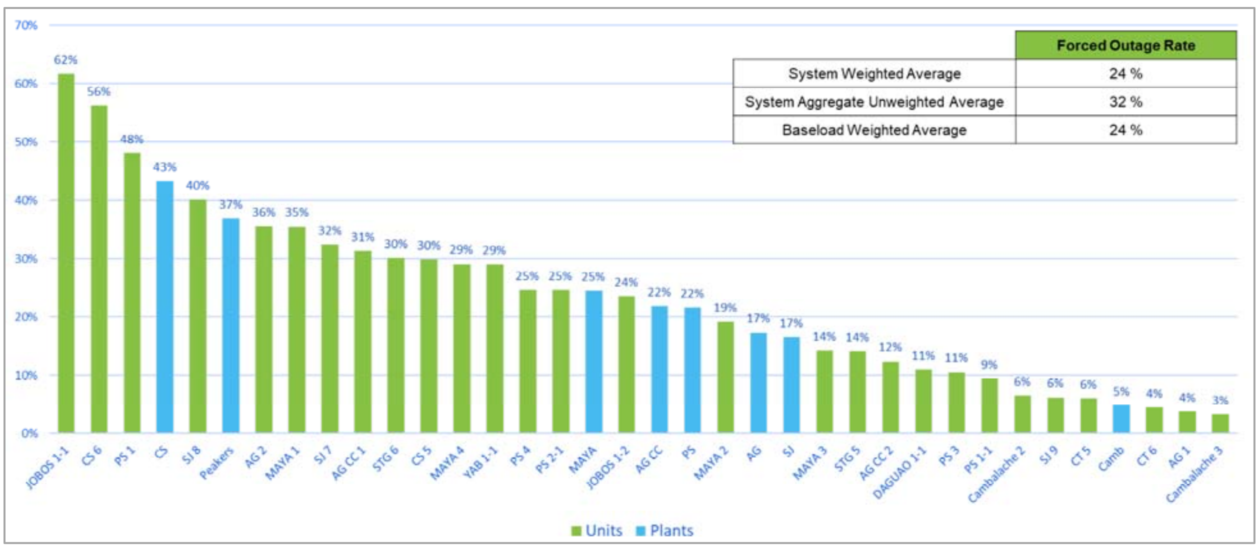


Table A-10: Recommended Forced Outage Rate Model Inputs

Unit	2020 Forced Outage Rate Input	2021 Forced Outage Rate Input	2022 Recommended Input
SJ CC 5	3.31	5.39	7
SJ CC 6	4.54	7.45	7
SJ 7	42.82	22.77	30
SJ 8	30.78	30.75	30

Unit	2020 Forced Outage Rate Input	2021 Forced Outage Rate Input	2022 Recommended Input
SJ 9	8.62	10.34	10
SJ 10	100	-	-
PS 1	42.69	42.69	20
PS 2	100	-	-
PS 3	4.09	4.91	15
PS 4	8.3	9.96	15
CS 5	58.52	12.04	10
CS 6	98.32	2.89	15
AG 1	5.23	6.28	10
AG 2	21.74	2.29	10
AG CC 1	25.89	8.78	40
AG CC 2	1.67	2	30
MAYA 1	8.47	10.16	30
MAYA 2	28.14	33.77	30
MAYA 3	4.23	5.08	30
MAYA 4	28.52	28.52	-
CAMB 1	100	100	-
CAMB 2	1	9.6	10
CAMB 3	0	1.2	10
Peakers	20	24	40

$$\text{Forced Outage Rate} = \frac{\text{Forced Outage Hours}}{\text{Service Hours + Forced Outage Hours}}$$

Figure A-12: Forced Outage Hours, Modeled vs. Actual – 2021

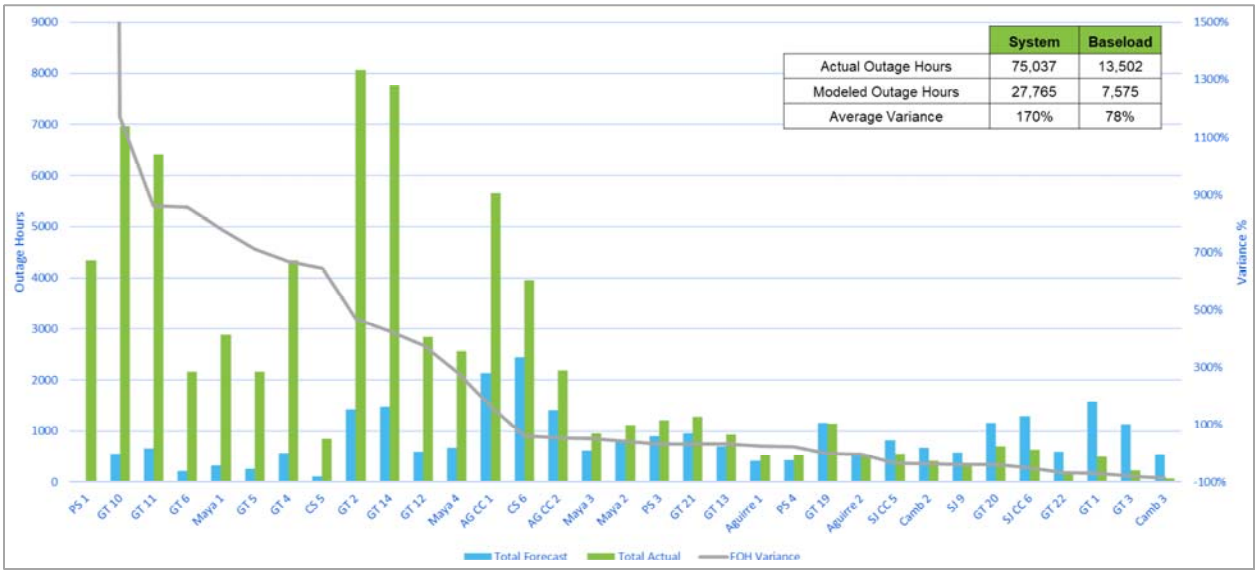


Table A-11: Annual Forced Outage Rate, 2013–2021

Unit	2013	2014	2015	2016	2017	2018	2019	2020	2021	Tot Avg
SJ CT 5	15	2	2	16	98	7	10	4	7	17.9%
SJ STG 5	13	2	3	6	8	8	44	8	4	10.7%
SJ CT 6	1	51	30	5	5	2	7	6	2	12.1%
SJ STG 6	5	17	28	7	6	3	8	60	21	17.2%
SJ 7	7	7	5	11	7	12	49	52	45	21.7%
SJ 8	3	5	3	13	12	28	0	73	100	26.3%
SJ 9	3	6	2	9	19	48	8	9	7	12.3%
SJ 10	8	49	97	100	100	100	100	100	100	83.8%
PS 1	8	15	7	3	4	14	18	47	100	24.0%
PS 2	2	1	6	13	100	100	100	100	100	58.0%
PS 3	15	0	6	10	61	15	10	6	28	16.8%
PS 4	3	2	93	100	100	100	68	9	7	53.6%
CS 5	0	2	1	0	0	5	10	59	11	9.8%
CS 6	4	0	2	12	12	1	2	98	47	19.8%
AG 1	2	6	27	7	7	6.46	1.21	5.39	7.22	7.7%
AG 2	3	2	11	100	15	3.25	77.11	27.1	8.70	27.5%
AG CC 1	20	9	6	14	47	53.84	16.93	34.96	44.92	27.4%
AG CC 2	3	10	37	63	39	50.48	5.49	2.6	59.61	30.0%

Unit	2013	2014	2015	2016	2017	2018	2019	2020	2021	Tot Avg
PS 1-1	100	0	99	97	49	10	9	1	19.00	42.7%
PS 2-1	0	0	71	100	100	100	71	32	32	56.2%
AG 2-1	0	98	0	79	92	91	100	100	100	73.3%
MAYA 1	90	18	0	0	0	48	26	21	100	33.7%
MAYA 2	65	46	0	0	0	100	31	48	26	35.1%
MAYA 3	47	42	0	0	0	75	49	9	25	27.4%
MAYA 4	0	0	0	0	0	17	0	52	62	14.6%
YAB 1-1	81	0	0	0	29	0	0	2	99	23.4%
JOBOS 1-1	100	97	100	100	99	100	100	85	47	92.0%
JOBOS 1-2	100	98	44	92	83	99	30	39	34	68.8%
DAGUAO 1-1	97	0	0	0	0	4	51	8	47	23.0%

Table A-12: Monthly Forced Outage Hours – 2021

Unit	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Outage %
Aguirre 1	0	0	0	0	0	42	162	35	99	45	0	143	6%
Aguirre 2	0	0	11	0	7	0	0	0	0	353	153	11	6%
AG CC 1	329	277	176	720	744	353	682	495	28	381	720	744	64%
AG CC 2	0	0	0	720	744	720	0	0	0	0	0	0	25%
Camb 2	12	0	0	224	187	1	1	0	0	0	0	0	5%
Camb 3	50	0	0	0	0	2	0	0	11	0	14	0	1%
SJ CC 5	3	0	0	0	388	12	0	6	68	55	2	18	6%
SJ CC 6	0	15	0	0	42	14	0	6	0	127	211	216	7%
PS 1-1	250	72	72	0	0	0	16	8	26	6	48	0	6%
PS 1-2	744	672	594	216	700	720	744	744	720	744	720	744	92%
PS 2-1	0	0	0	125	0	0	8	24	72	—	—	—	3%
PS 2-2	744	672	744	720	744	720	—	—	—	—	—	—	100%
PS 3-1	744	672	744	—	—	—	—	—	—	—	—	—	100%
PS 3-2	744	672	744	—	—	—	—	—	—	—	—	—	100%
AG 2-2	744	672	744	720	744	700	700	399	349	109	341	744	80%
Yab 1-1	744	0	576	720	0	720	744	742	719	700	0	744	73%
Yab 1-2	0	668	739	720	0	720	—	—	—	—	—	—	66%

Unit	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Outage %
Aguirre 1	0	0	0	0	0	42	162	35	99	45	0	143	6%
VB 1-1	0	384	550	0	0	0	—	—	—	—	—	—	22%
VB 1-2	744	672	744	720	744	720	744	225	225	744	720	744	88%
Jobos 1-1	68	75	306	221	5	5	15	216	216	19	0	0	13%
Jobos 1-2	0	0	240	178	0	0	0	48	48	0	96	96	8%
Daguao 1-1	600	672	0	0	0	0	0	0	0	0	0	0	15%
Daguao 1-2	0	0	200	0	0	0	0	0	0	0	0	0	2%
Maya 1	744	672	744	0	0	720	—	—	—	—	—	—	66%
Maya 2	0	0	0	0	372	0	200	347	200	0	0	0	13%
Maya 3	0	326	200	200	200	8	8	8	4	0	0	0	11%
Maya 4	0	0	0	0	0	360	372	372	360	372	360	372	29%
PS 1	744	672	744	720	744	720	—	—	—	—	—	—	100%
PS 3	0	0	0	0	0	0	234	353	191	109	45	282	14%
PS 4	0	50	27	0	0	7	118	10	65	247	11	0	6%
SJ 9	0	0	0	0	0	127	49	0	88	0	67	30	4%
CS 5	0	81	47	0	0	0	18	0	409	141	21	139	10%
CS 6	664	139	3	0	8	25	0	218	720	744	720	707	45%

Figure A-13: San Juan 5 and 6 Forced Outage Data

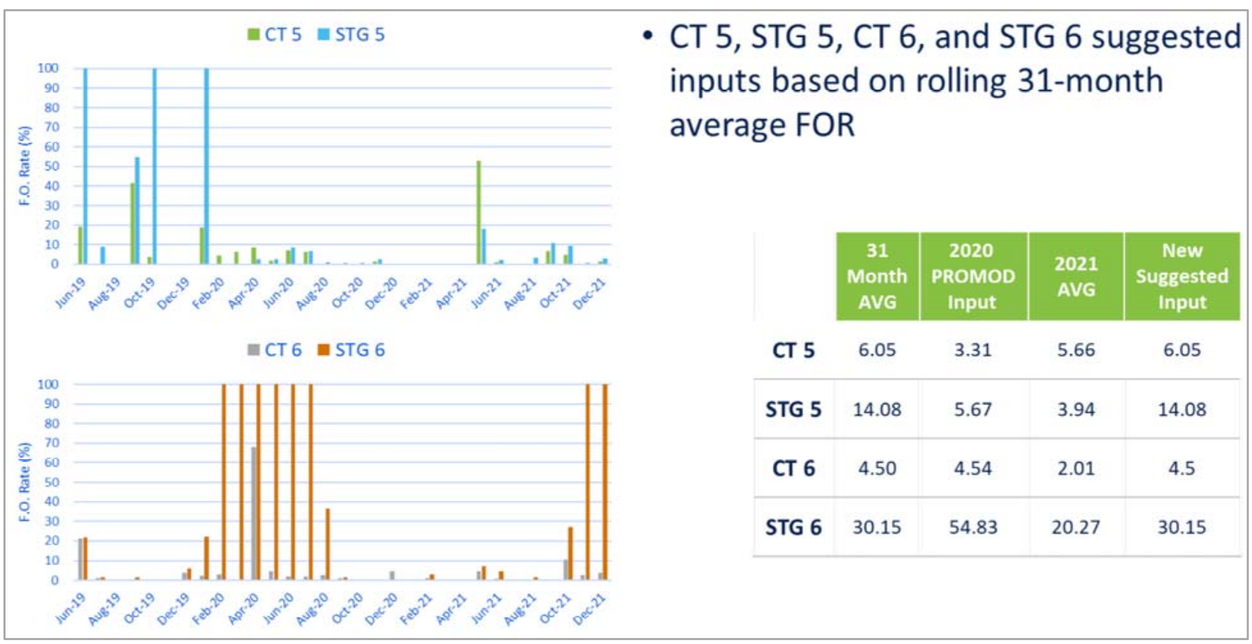
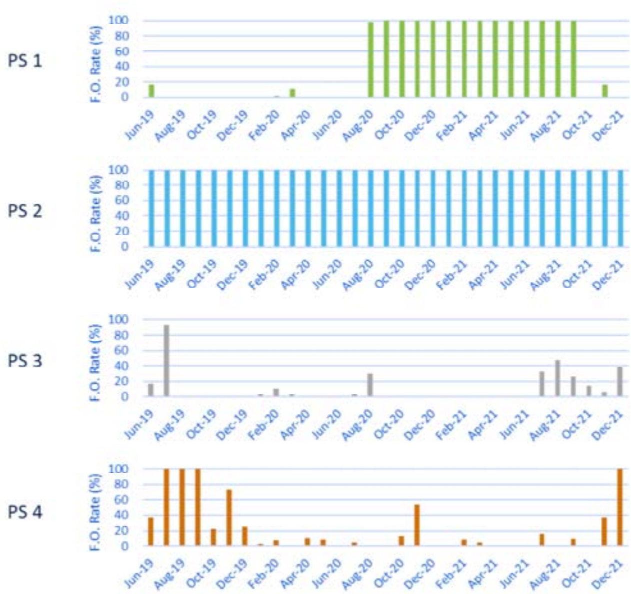


Figure A-14: San Juan 7–10 Forced Outage Data

- SJ 7 and SJ 9 suggested input based on rolling 31-month average FOR
- SJ 8 and SJ 10 are out of service

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
SJ 7	32.46	42.82	12.41	32.46
SJ 8	40.15	30.78	58.28	-
SJ 9	6.23	8.62	4.42	6.23
SJ 10	100	100	100	-

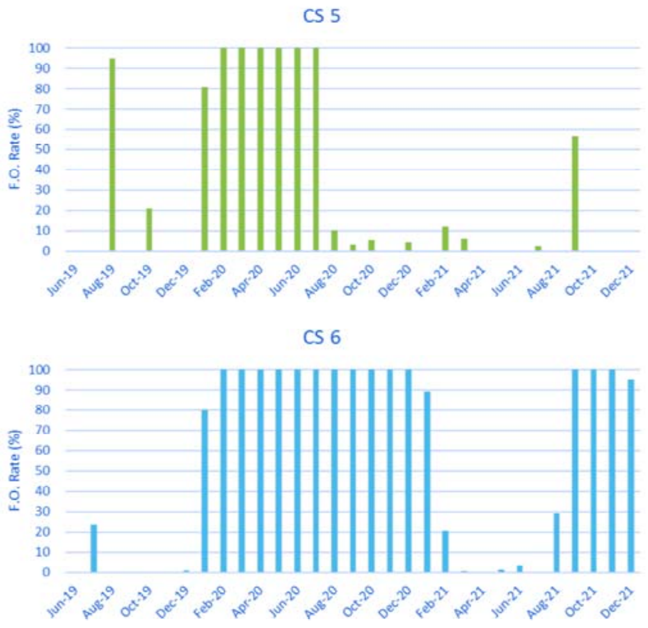
Figure A-15: Palo Seco Forced Outage Data



- PS 3 and PS 4 suggested input based on rolling 31-month average FOR
- PS 1 and PS 2 are out of service

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
PS 1	48.11	42.69	83.28	-
PS 2	100	100	100	-
PS 3	10.54	4.09	13.81	10.54
PS 4	24.55	8.3	16.13	24.55

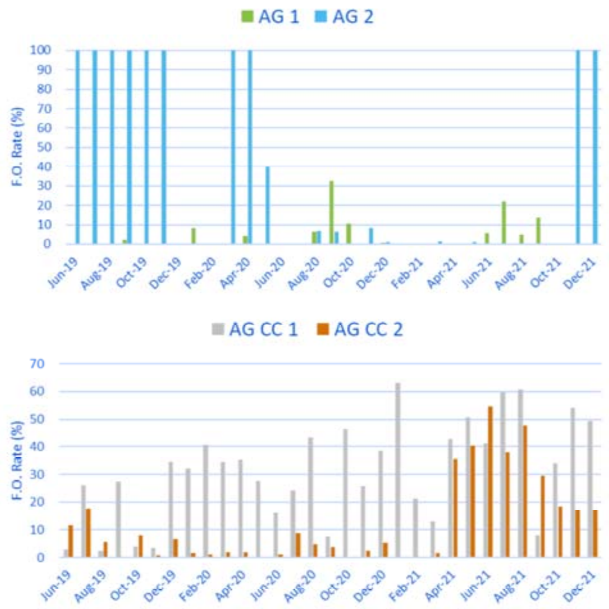
Figure A-16: Costa Sur 5 & 6 Forced Outage Data



- CS 5 suggested input based on the previous input
- CS 6 suggested input based on the 2021 average FOR

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
CS 5	29.91	58.52	7.05	12.03
CS 6	56.28	98.32	44.98	44.98

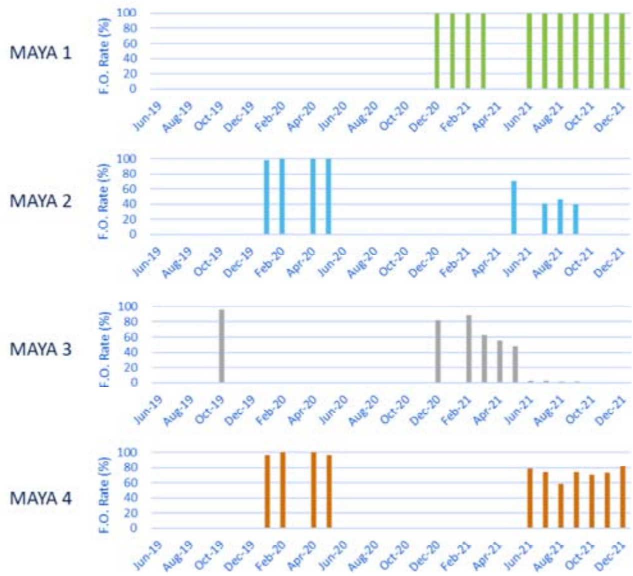
Figure A-17: Aguirre Forced Outage Data



- AG 1, AG CC 1, and AG CC2 suggested inputs based on the 2021 average FOR
- AG 2 suggested input based on rolling 31 Month Average

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
AG 1	3.73	5.23	4.20	4.2
AG 2	35.52	21.74	18.42	35.52
AG CC 1	31.31	25.89	41.49	41.49
AG CC 2	12.36	1.67	24.99	24.99

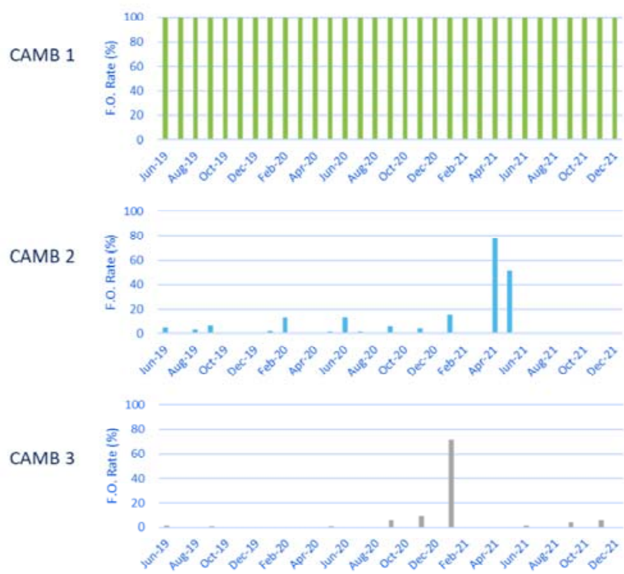
Figure A-18: Mayagüez Forced Outage Data



- MAYA 2 and MAYA 3 suggested inputs based on rolling 31-month average FOR
- Maya 1 and MAYA 4 suggested input based on rolling 6-month average FOR

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
MAYA 1	35.48	8.47	83.33	100
MAYA 2	19.20	28.14	16.42	19.2
MAYA 3	14.23	4.23	21.88	14.23
MAYA 4	29.09	28.52	42.4	71.68

Figure A-19: Cambalache Forced Outage Data



- CAMB 2 and CAMB 3 suggested inputs based on rolling 31-month average FOR
- CAMB 1 is out of service

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
CAMB 1	100	100	100	-
CAMB 2	6.50	1	12.17	6.5
CAMB 3	3.26	0	6.83	3.26

Figure A-20: Gas Turbine Peakers Forced Outage Data

- Peakers are all given 20% FOR based on multiple factors and due to the sporadic use of these units

	31 Month AVG	2020 PROMOD Input	2021 AVG	New Suggested Input
PS 1-1	9.39	20	17.00	40
PS 2-1	24.54	20	21.40	40
JOBOS 1-1	61.70	20	37.00	40
JOBOS 1-2	23.54	20	22.54	40
AG 2-1	100	20	100	40
YAB 1-1	29.03	20	74.43	40
DAGUAO 1-1	11.02	20	16.61	40

Appendix 9. Forced Outage – Sensitivity Analysis

As part of the overall validation process, a sensitivity analysis was performed to determine the impact of modeled generator forced outage duration on LOLE and LOLH model output. Five different forced outage durations were considered (keeping individual generator forced outage rates constant across all scenarios): 20 hours, 40 hours, 60 hours, 80 hours, and 100 hours. Note that for each scenario, the modeled outage duration was applied for all generators, i.e., for the 100-hour forced outage duration scenario, a forced outage for each of the generators was assumed to last 100 hours. The results of the sensitivity simulations are provided in the table below.

As forced outage durations increase, there is a slight decrease in LOLE but no discernable difference in LOLH. The marginal difference in LOLE is due to the fact that as forced outage duration increases, while keeping forced outage rates constant, generators experience the same total number of hours of forced outages, but these occur across less forced outage events. The relationship between forced outage rates and forced outage duration in the model is as follows. If for example a generator has a forced outage rate of 10%, meaning it is expected to be out of operation for approximately 880 hours in a year, and a forced outage duration of 40 hours, the model will randomly distribute 22 forced outage events for that generator throughout the year (880 hours of forced outage / average repair time of 40 hours). If the forced outage duration is then assumed to be 100 hours, the model will then randomly distribute approximately 9 forced outage events for that generator. Increasing the duration of each forced outage simply decreases the number of occurrences of forced outage events. For this reason, the model output shows that there are slightly fewer days that experience a loss of load event when forced outages are longer; even though the generators experience the same total forced outage hours, their outages are more concentrated across fewer days and that is why there is a slight reduction in LOLE. Note however that this reduction starts leveling-off as forced outage duration increases. Even if all generators only experienced one long forced outage per year, those outage events would affect system performance leading to loss of load events.

Table A-13: Forced Outage Duration LOLE and LOLH Comparison

Scenario (Current System)	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
20-Hour Forced Outage Duration	10.82 Days / Year	40.54 Hours / Year
40-Hour Forced Outage Duration	8.81 Days / Year	40.77 Hours / Year
60-Hour Forced Outage Duration	8.04 Days / Year	40.38 Hours / Year
80-Hour Forced Outage Duration	7.73 Days / Year	41.20 Hours / Year
100-Hour Forced Outage Duration	7.58 Days / Year	41.00 Hours / Year

These sensitivities were performed to understand the impact of this specific model input on model results. The results are not meant to be used as an assessment of whether shorter or longer duration forced outages are somehow more beneficial for system performance. Any forced outage, regardless of its duration, has the potential to lead to a loss of load event, especially since their occurrence cannot be predicted.

All the results discussed in this report assume a 40-hour duration for each forced outage event for all generators. In reality, forced outage durations vary across generators and depend on the specific cause

of such outage. Generators in Puerto Rico have experienced a range of forced outage durations including short events caused by typical wear and tear or minor problems as well as extended outage events caused by hurricanes, earthquakes, and the loss of major pieces of equipment such as the transformer in one of the Aguirre Steam units. When modeling forced outages, the forced outage rates (which are based on historical generator performance and are a good indication of expected generator availability), rather than the forced outage durations, are the more important metric for the purposes of these resource adequacy evaluations.

Appendix 10. Planned Outage Rates – PREPA Units

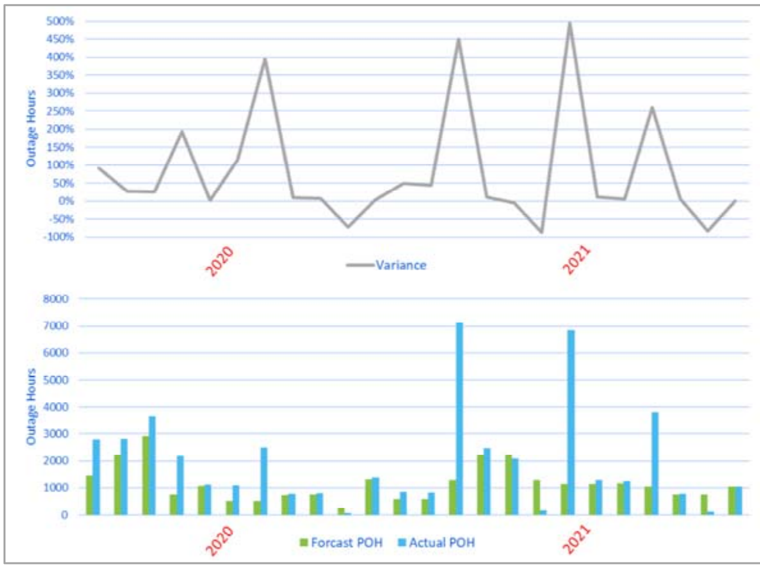
The planned outage rate assumption is another key factor that affects the modeled availability and reserves throughout the year. PREPA plants have historically exceeded their planned outage durations by a significant amount. Most utilities tightly manage their outage schedules and outage performance and pre-plan their outages two or more years in advance. Outage schedules are tightly monitored and delays of even a few days are uncommon since the parts have been pre-ordered or are on-site, and labor resources are identified. In this environment, planed outage rate performance against schedule is taken as a reliable input.

PREPA has historically exceeded outage schedule durations by approximately 20%. This is even after excluding three outages that had delays of 6-9 months, which would have resulted in an average schedule variance of 66% longer than scheduled for the entire generation fleet if included in totals. This is significantly higher than industry averages.

The reliability of planned outage assumptions affects resource adequacy results since it means plants on outages will not be available for 20% more hours during the period than planned. After analyzing the data and the implications, LUMA decided to not directly adjust planned outage schedules for the expected schedule overruns because we needed to rely upon the generators for their best estimates and we did not consider it appropriate to develop our own outage schedules based upon statistical adjustments; however, we needed to explicitly recognize the impact of this assumption in analyzing results. What this means is that the risk of load shed events is likely higher than we state in the report and the expected availability of plant resources is likely much less than stated in our results. The planned outage performance record was considered when considering forced outage rates as a justification for sometimes having a bias to slightly higher forced outage rates (forced outage rates are described in Appendix 8).

The following pages describe the planned outage performance against scheduled for each of the PREPA units. We evaluated planned outage performance in aggregate and for each individual unit to select the data values shown in the following pages.

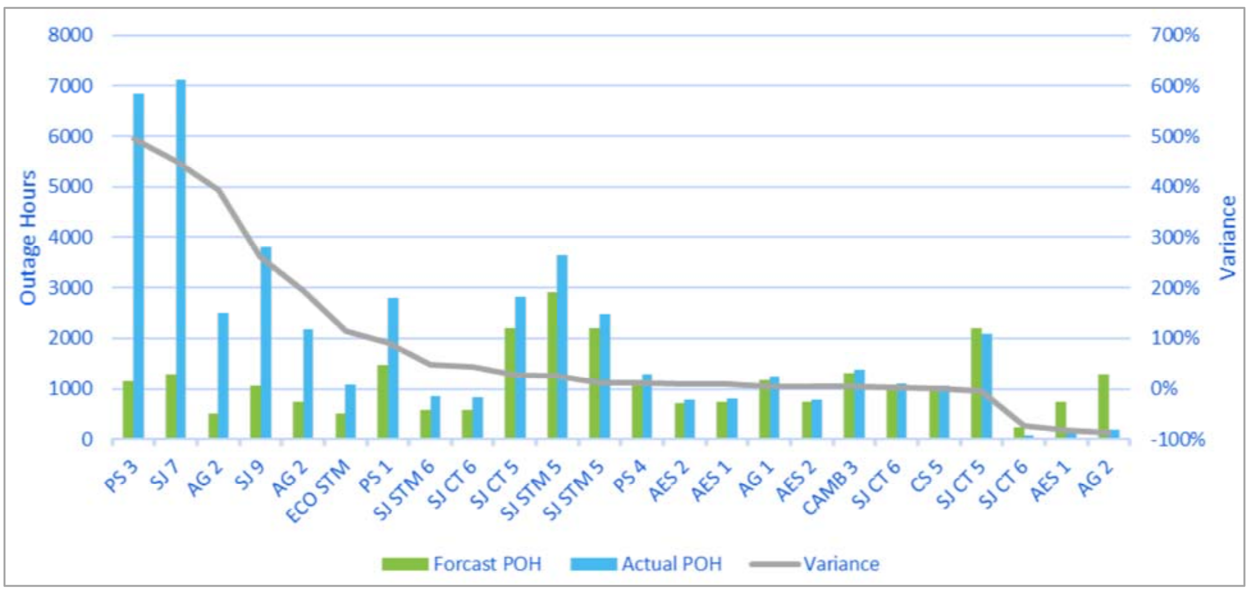
Figure A-21: Planned Outages vs. Forecast, October 2019–December 2021



Plant	Forecast Outage Hours	Actual Outage Hours	Variance
AES 1	1488	937	-37%
CS 5	1056	1051	0%
SJ 8	1080	1112	3%
Camb 3	1320	1380	5%
SJ STM 5	5856	6129	5%
SJ CT 6	1896	2003	6%
AG 1	1176	1243	6%
AES 2	1464	1572	7%
SJ CT 5	4416	4919	11%
PS 4	1152	1285	12%
SJ STM 6	576	856	49%
AG 2	2544	4813	89%
PS 1	1464	2798	91%
ECO STM	504	1082	115%
SJ 9	1056	3810	261%
SJ 7	1296	7125	450%
PS 3	1152	6847	494%
Total	29496	48962	66%

Planned outages last 66% longer than forecast on an aggregated basis.

Figure A-22: Planned Outage Hours, Forecast vs. Actual – October 2019–December 2021



Most outages lasted an average of 20% longer than scheduled when excluding the one-time underperformance of PS 3, SJ 7, and SJ 9, which significantly influenced the overall variance of the system.

Figure A-23: Average Planned Outage Rate by Plant and Unit – June 2019–December 2021

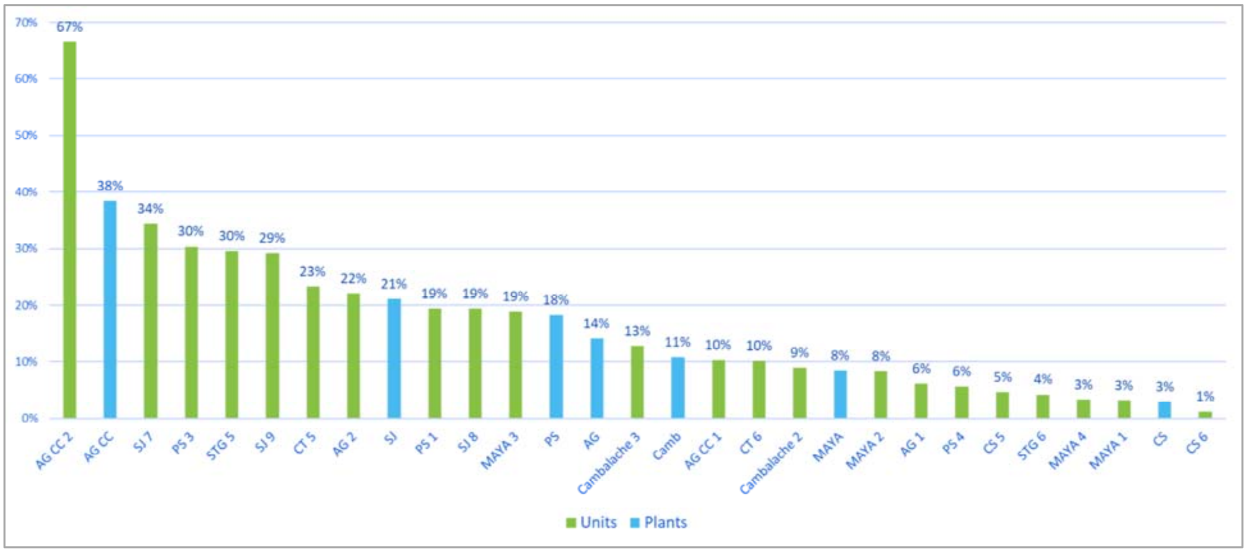


Table A-14: Annual Planned Outage Rate from 2013 to 2021

Unit	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total Avg
SJ 5	4%	51%	4%	2%	8%	10%	24%	11%	24%	15%
SJ ST 5	0%	51%	4%	2%	9%	10%	17%	27%	28%	16%
SJ 6	12%	17%	50%	16%	0%	12%	8%	22%	1%	15%
SJ ST 6	15%	18%	50%	18%	0%	12%	9%	9%	2%	15%
SJ 7	22%	13%	12%	18%	32%	71%	39%	14%	67%	32%
SJ 8	35%	0%	22%	0%	69%	0%	46%	0%	0%	19%
SJ 9	0%	18%	0%	20%	0%	35%	70%	3%	43%	21%
SJ 10	0%	44%	0%	0%	0%	0%	0%	0%	0%	5%
PS 1	0%	14%	14%	1%	33%	32%	44%	7%	0%	16%
PS 2	14%	0%	15%	16%	33%	59%	0%	0%	0%	15%
PS 3	68%	100%	75%	0%	37%	0%	0%	28%	50%	40%
PS 4	0%	47%	0%	0%	0%	17%	39%	5%	9%	13%
CS 5	51%	13%	9%	0%	26%	10%	0%	0%	12%	13%
CS 6	0%	16%	10%	3%	0%	20%	0%	0%	3%	6%
AG 1	13%	35%	4%	0%	20%	0%	11%	0%	14%	11%
AG 2	13%	0%	12%	0%	0%	16%	8%	16%	29%	11%
AG CC 1	25%	33%	32%	7%	5%	3%	7%	4%	1%	13%
AG CC 2	1%	0%	12%	14%	20%	27%	51%	48%	55%	25%

Table A-15: Monthly Planned Outage Hours – 2021

Unit	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Outage %
Aguirre 1	1	672	570	0	0	0	0	24	0	0	0	0	14%
Aguirre 2	61	0	0	0	120	720	744	744	163	0	0	0	29%
AG CC 1	0	0	0	0	0	0	0	0	0	0	0	0	0%
Camb 2	130	0	10	9	0	0	400	311	0	0	0	0	10%
Camb 3	0	0	8	0	0	0	0	0	229	0	0	0	3%
SJ CC 5	79	569	744	720	134	0	0	0	0	0	0	0	26%
SJ CC 6	39	0	0	0	87	23	0	0	0	0	0	0	2%
Maya 1	0	0	0	0	0	0	0	0	0	0	0	0	0%
Maya 2	0	0	0	225	0	0	0	0	0	0	0	0	3%
Maya 3	0	0	98	98	120	0	0	0	0	0	0	0	4%
Maya 4	0	0	0	0	0	0	0	0	0	0	0	0	0%
PS 3	744	672	744	720	744	720	8	0	0	0	0	0	50%
PS 4	744	61	0	0	0	0	0	9	0	0	0	0	9%
SJ 7	744	672	744	720	744	720	744	744	21	0	0	0	67%
SJ 9	744	672	744	720	744	113	0	0	0	0	0	0	43%
CS 5	0	0	0	696	355	0	0	0	0	0	0	0	12%
CS 6	0	0	283	0	0	0	0	0	0	0	0	0	3%

Appendix 11. Maximum Effective Capacity – PREPA Units

To calculate the maximum effective capacity for each unit, LUMA reviewed the past three years of generation data for each unit. Initially, LUMA calculated the 95th percentile of hourly generation production that each unit achieved for each of the past three years. In other words, the maximum generation output that each unit was capable of producing for at least 95% of the hours in the year was determined, even if this was not consecutive hourly production. The rational for this is that for baseload units, Systems Operation would typically request the units to produce the highest production capacity they can safely and reliably maintain each day, since these are the most efficient units. If the units occasionally produced more than that capacity for less than 5% of the hours, that was judged to not be reliably effective capacity for planning purposes.

The maximum effective capacity assumed for modeling in the resource adequacy analysis is summarized in the table below and the supporting analysis for each unit in the PREPA portfolio is discussed in the pages that follow in this appendix.

Table A-16: Summary of Available Thermal Generator Capacity in FY2023

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)
AES 1	2002	Coal	227	227
AES 2	2002	Coal	227	227
Aguirre Combined Cycle 11	1977	Diesel	296	220
Aguirre Combined Cycle 21	1977	Diesel	296	100
Aguirre Steam 1	1971	Bunker	450	370
Aguirre Steam 2	1971	Bunker	450	350
Costa Sur 5	1972	Natural Gas	410	350
Costa Sur 6	1973	Natural Gas	410	350
EcoEléctrica	1999	Natural Gas	530	530
Palo Seco 3	1968	Bunker	216	190
Palo Seco 4	1968	Bunker	216	160
San Juan 7	1965	Bunker	100	70
San Juan 9	1968	Bunker	100	95
San Juan Combined Cycle 5	2008	Diesel / Natural Gas	220	200
San Juan Combined Cycle 6	2008	Diesel / Natural Gas	220	200
Cambalache 2	1998	Diesel	82.5	76
Cambalache 3	1998	Diesel	82.5	75
Mayagüez 12	2009	Diesel	55	50

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)
Mayagüez 2	2009	Diesel	55	50
Mayagüez 3	2009	Diesel	55	50
Mayagüez 4	2009	Diesel	55	50
Palo Seco Mobile Pack 1-33	2021	Diesel	27 each (81 total)	81
7 Gas Turbines (Peakers)4	1972	Diesel	21 each (147 total)	147
Total			**4,981**	**4,218**

Notes:

1. The steam cycle on both Aguirre Combined Cycle power plants is currently inoperable. Repair timing is uncertain.
2. Mayagüez 1 is currently out of service but is expected come back into service sometime in 2022. This analysis considers it will come back into service on January 1, 2023.
3. The Palo Seco Mobile Pack units are expected to return to service sometime in 2022. This analysis considers they will come back into service on January 1, 2023.
4. A total of 18 gas turbines, each with a capacity of 21 MW, are installed. Only 7 are considered to be operational.

Figure A-24: San Juan CC 5, Hourly Generation – 2019–2021

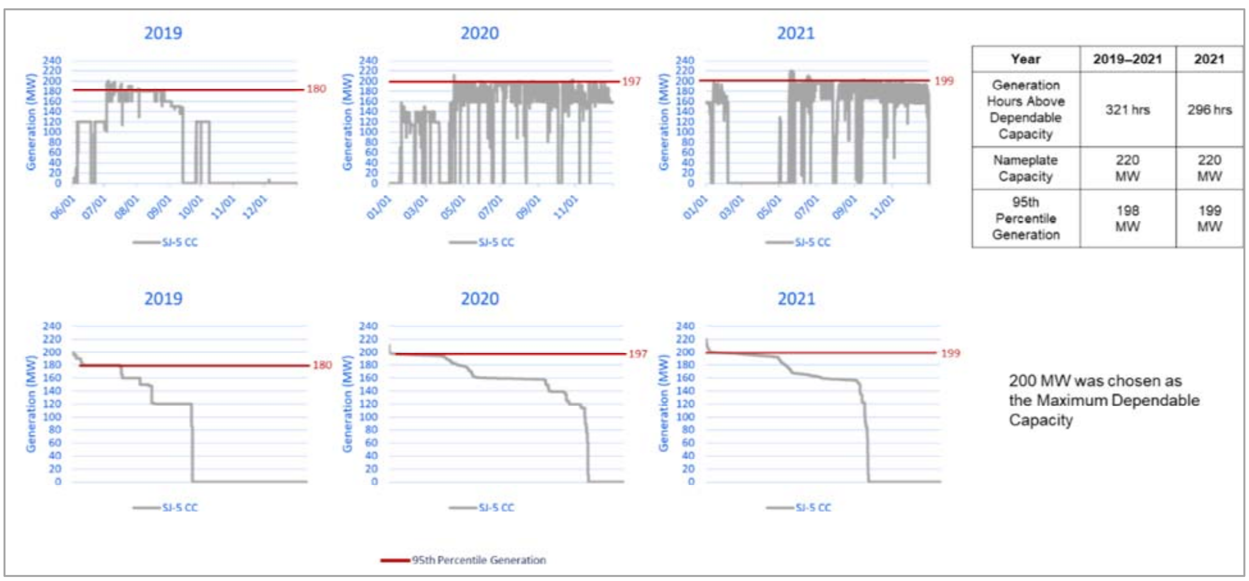


Figure A-25: San Juan CC 6, Hourly Generation – 2019–2021

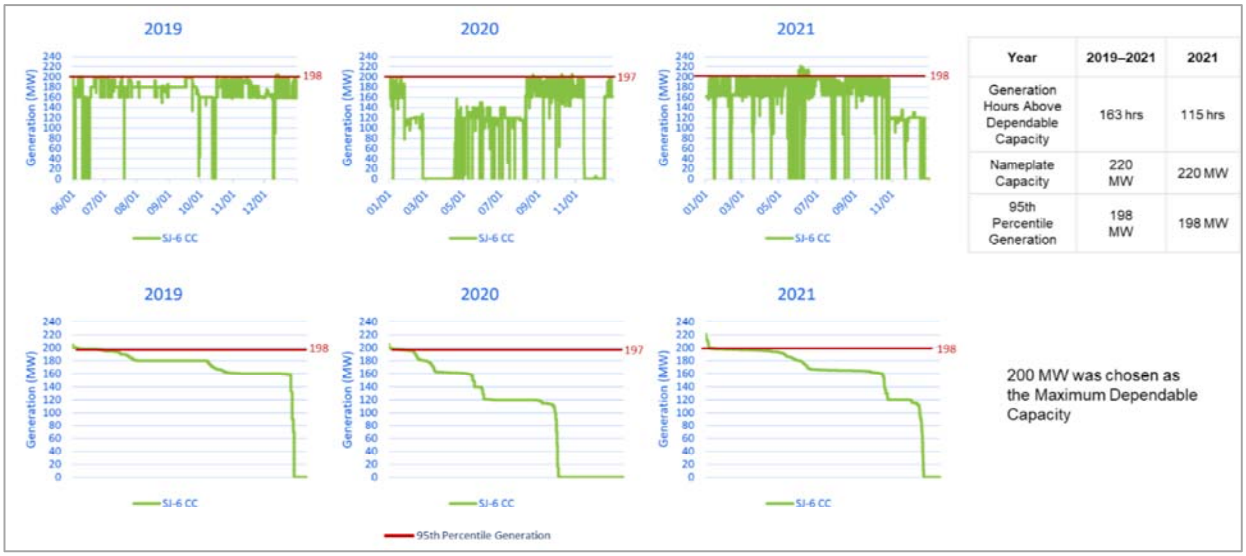


Figure A-26: San Juan 7, Hourly Generation – 2019–2021

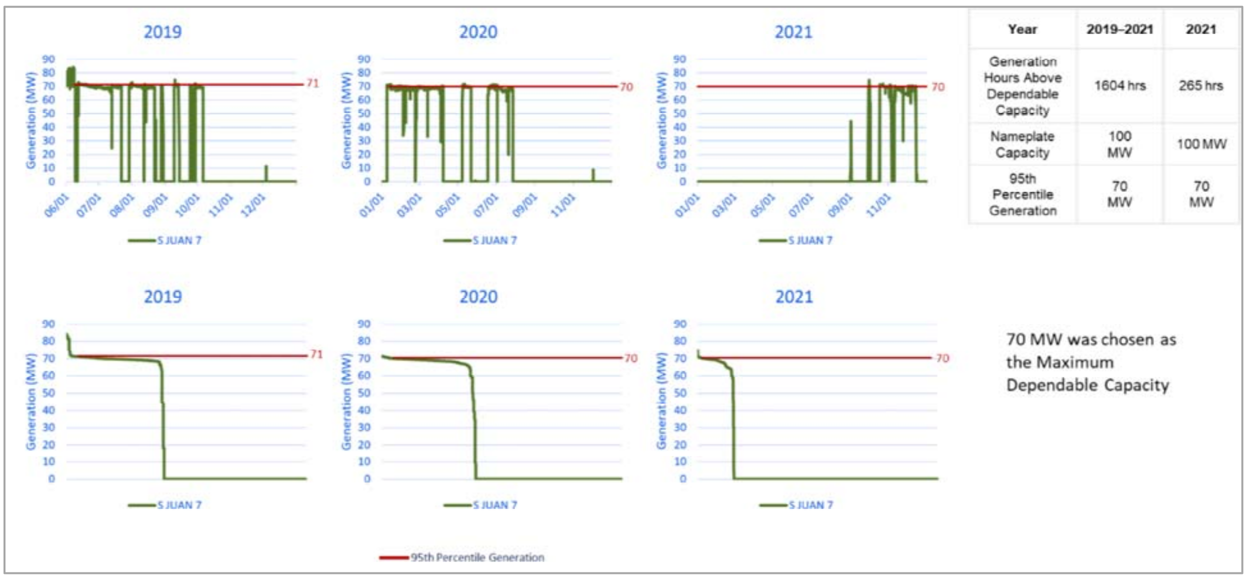


Table A-17: San Juan 8, Hourly Generation – 2019–2021

Nameplate Capacity	100 MW
95th Percentile Generation (2021)	0 MW
Maximum Dependable Capacity	0 MW

San Juan 8 is out of service.

Figure A-27: San Juan 9, Hourly Generation – 2019–2021

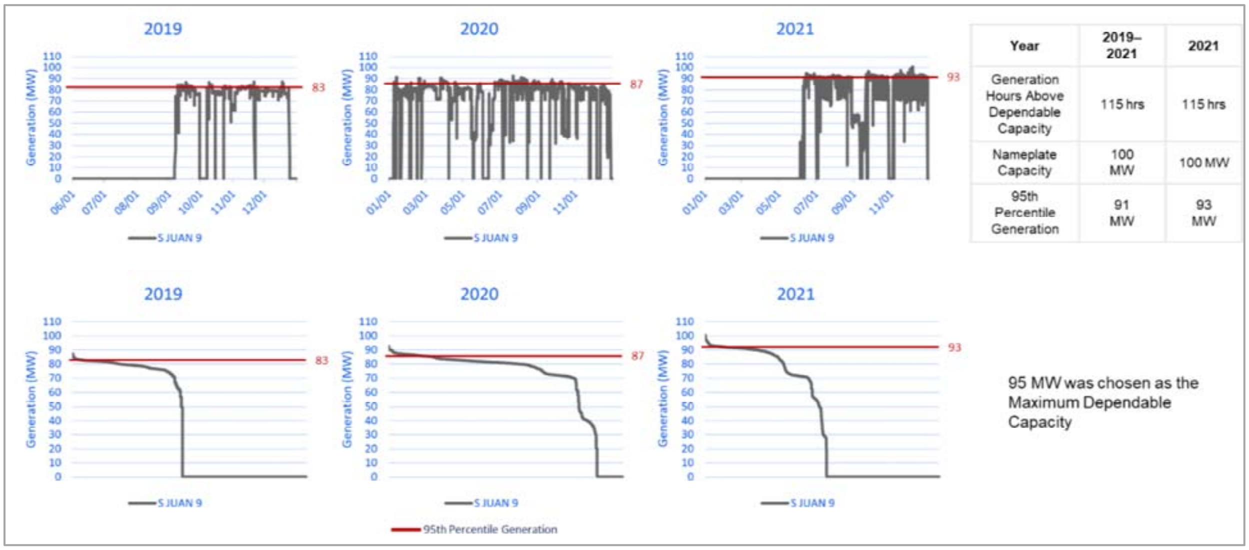


Table A-18: San Juan 10, Hourly Generation – 2019–2021

Nameplate Capacity	100 MW
95th Percentile Generation (2021)	0 MW
Maximum Dependable Capacity	0 MW

San Juan 10 is out of service.

Table A-19: Palo Seco 1, Hourly Generation – 2019–2021

Nameplate Capacity	85 MW
95th Percentile Generation (2021)	0 MW
Maximum Dependable Capacity	0 MW

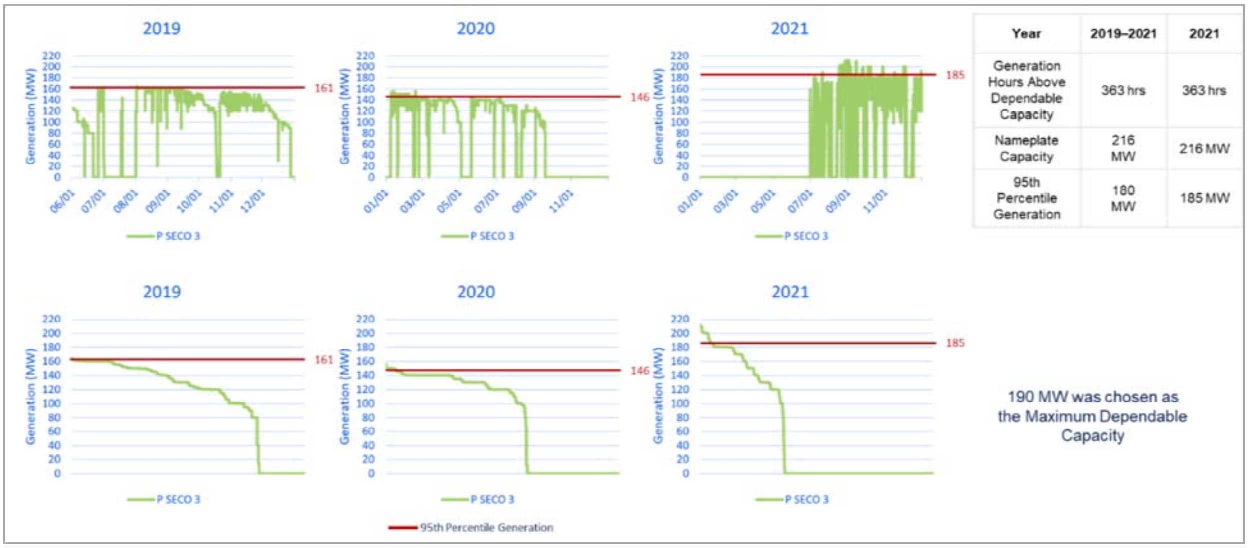
Palo Seco 1 is out of service.

Table A-20: Palo Seco 2, Hourly Generation – 2019–2021

Nameplate Capacity	85 MW
95th Percentile Generation (2021)	0 MW
Maximum Dependable Capacity	0 MW

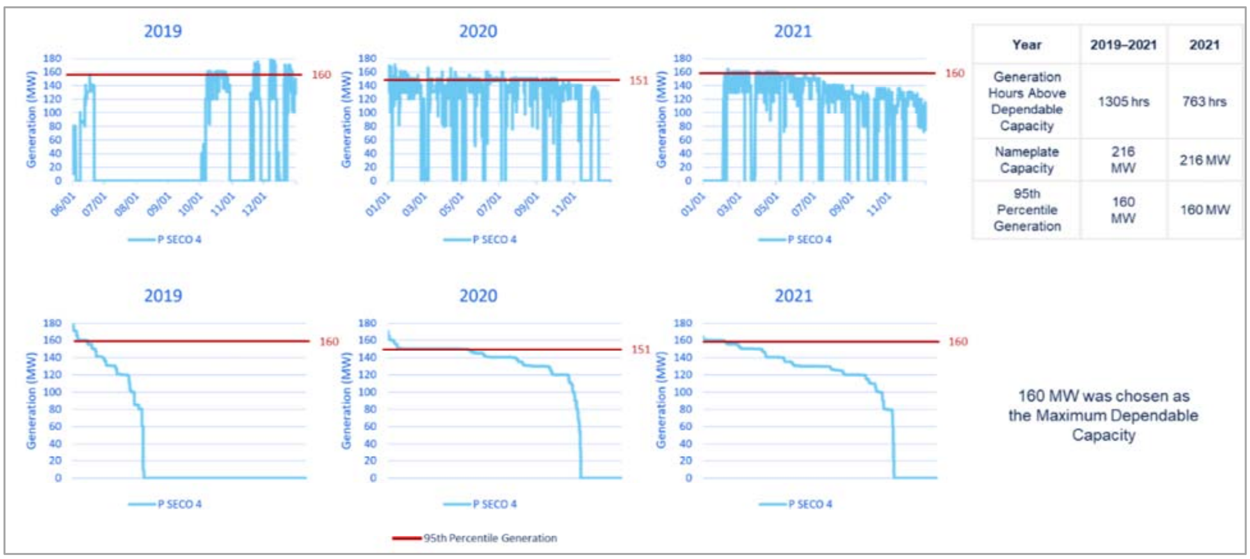
Palo Seco 2 is out of service.

Figure A-28: Palo Seco 3, Hourly Generation – 2019–2021



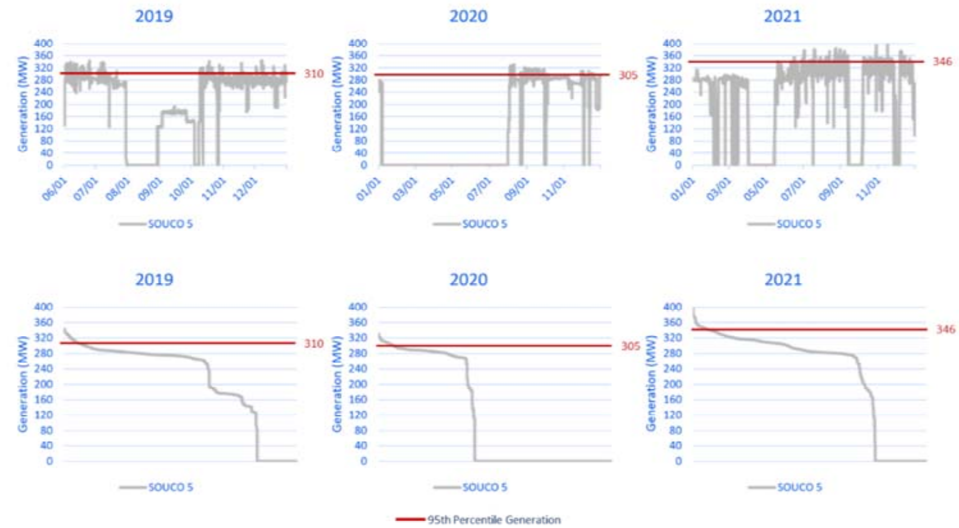
Year	2019–2021	2021
Generation Hours Above Dependable Capacity	363 hrs	363 hrs
Nameplate Capacity	216 MW	216 MW
95th Percentile Generation	180 MW	185 MW

Figure A-29: Palo Seco 4, Hourly Generation – 2019–2021



Year	2019–2021	2021
Generation Hours Above Dependable Capacity	1305 hrs	763 hrs
Nameplate Capacity	216 MW	216 MW
95th Percentile Generation	160 MW	160 MW

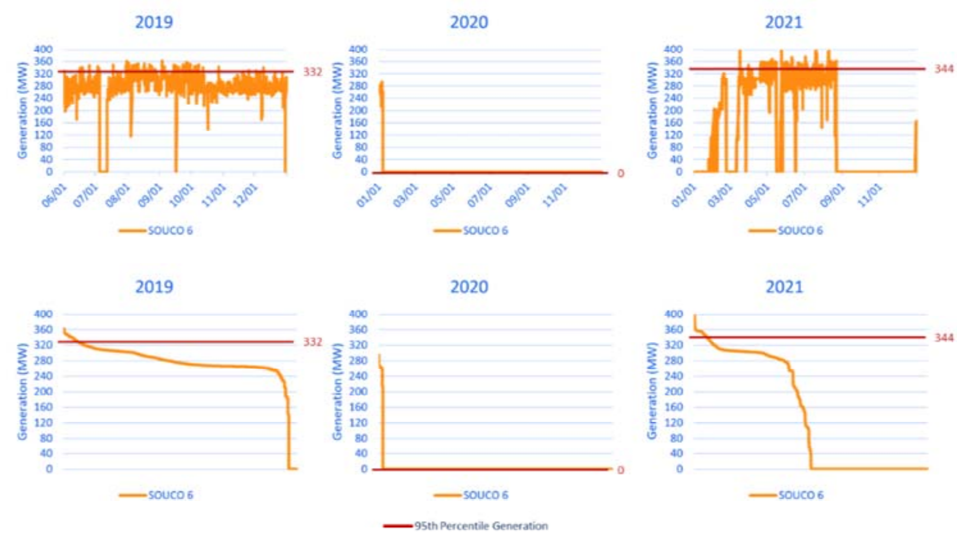
Figure A-30: Costa Sur 5, Hourly Generation – 2019–2021



Year	2019–2021	2021
Generation Hours Above Dependable Capacity	276 hrs	276 hrs
Nameplate Capacity	410 MW	410 MW
95th Percentile Generation	329 MW	346 MW

350 MW was chosen as the Maximum Dependable Capacity

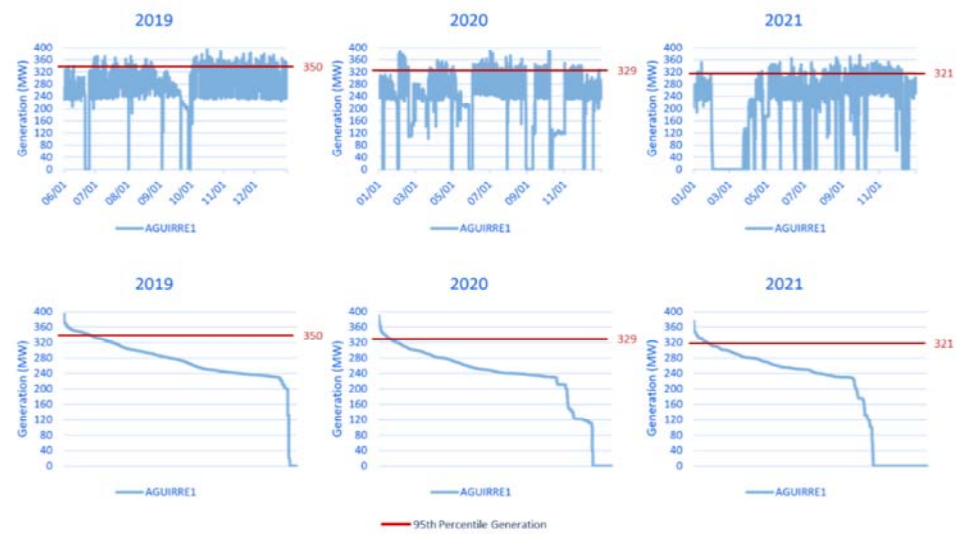
Figure A-31: Costa Sur 6, Hourly Generation – 2019–2021



Year	2019–2021	2021
Generation Hours Above Dependable Capacity	384 hrs	342 hrs
Nameplate Capacity	410 MW	410 MW
95th Percentile Generation	322 MW	344 MW

350 MW was chosen as the Maximum Dependable Capacity

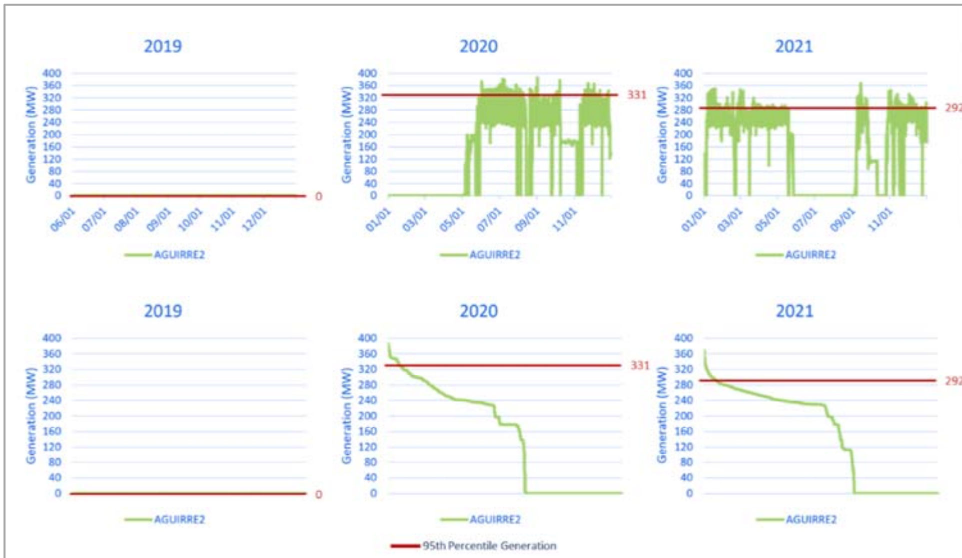
Figure A-32: Aguirre 1, Hourly Generation – 2019–2021



Year	2019–2021	2021
Generation Hours Above Dependable Capacity	76 hrs	5 hrs
Nameplate Capacity	450 MW	450 MW
95th Percentile Generation	335 MW	321 MW

370 MW was chosen as the Maximum Dependable Capacity

Figure A-33: Aguirre 2, Hourly Generation – 2019–2021



Year	2019–2021	2021
Generation Hours Above Dependable Capacity	121 hrs	6 hrs
Nameplate Capacity	450 MW	450 MW
95th Percentile Generation	304 MW	292 MW

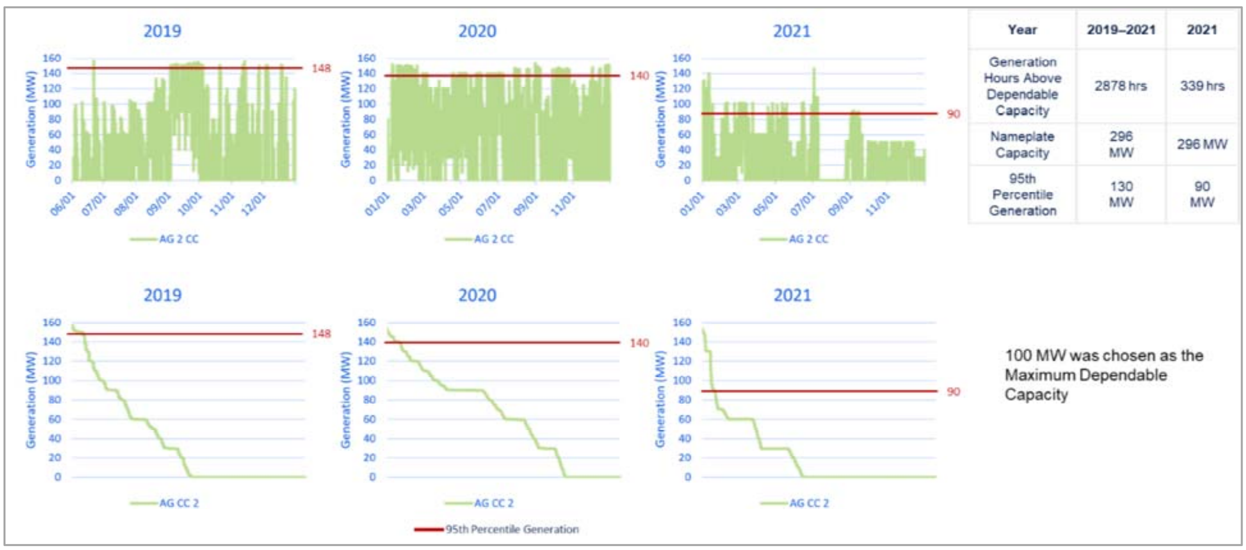
350 MW was chosen as the Maximum Dependable Capacity

Figure A-34: Aguirre 1 CC, Hourly Generation –2019–2021

Year	2019–2021	2021
Generation Hours Above Dependable Capacity	491 hrs	461 hrs
Nameplate Capacity	296 MW	296 MW
95th Percentile Generation	190 MW	222 MW

220 MW was chosen as the Maximum Dependable Capacity

Figure A-35: Aguirre 2 CC, Hourly Generation – 2019–2021



Year	2019–2021	2021
Generation Hours Above Dependable Capacity	2878 hrs	339 hrs
Nameplate Capacity	296 MW	296 MW
95th Percentile Generation	130 MW	90 MW

100 MW was chosen as the Maximum Dependable Capacity

Appendix 12. Results – Loss of Load Expectation

The following appendix provides more detail regarding the resource adequacy results that are summarized in the main body of this report.

Loss of Load Expectation

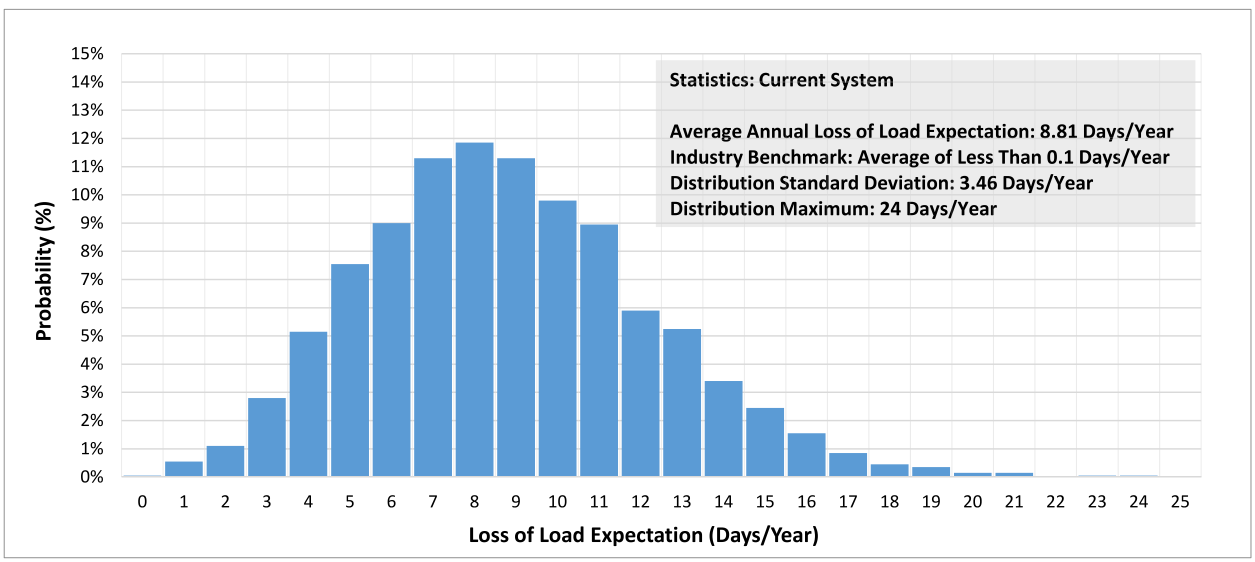
The following table summarizes the LOLE calculations for the current system in FY2023.

Table A-21: Calculated Loss of Load Expectation, Current System (FY2023)

Measure	Loss of Load Expectation (LOLE)
Average	8.81 Days / Year
Industry Benchmark Target	0.1 Days / Year
Distribution Standard Deviation	3.46 Days / Year
Distribution Maximum	24 Days / Year

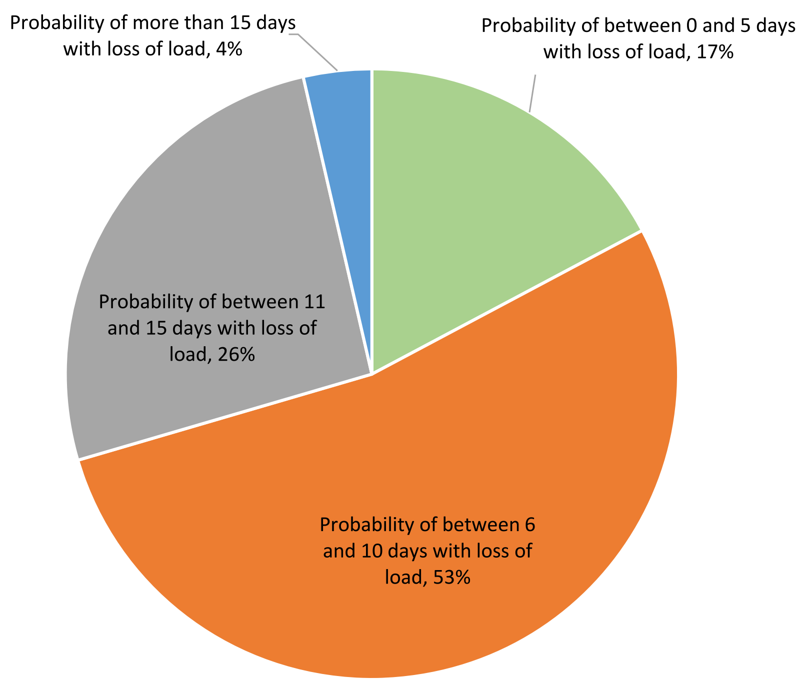
The following figure presents the probability of LOLE at various levels. The vertical axis represents probability, while the horizontal axis represents the number of days per year where system generators could not fully serve load. Based on the distribution, 8 days of loss of load is the most likely outcome. There is approximately a 50% probability that the number of days of loss of load will be equal to or greater than 9 days. Note that the figure does not forecast what will actually occur with respect to resource adequacy in FY2023; however, the figure does help to quantify the risk, or probability, of how many loss of load days might be expected in FY2023.

Figure A-36: Loss of Load Expectation Probability Chart, FY2023



The data in the previous figure can also be summarized in the following pie chart. As can be seen, only 8% of the simulations performed were found to have zero days of loss of load. In contrast, over 50% of the simulations performed had 3 or greater days of loss of load.

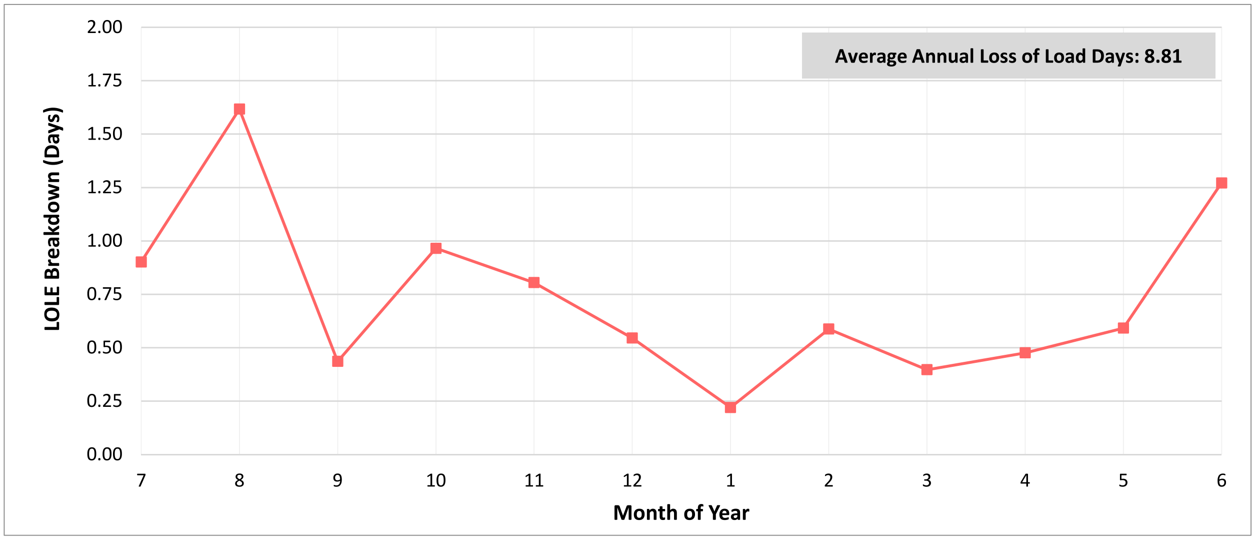
Figure A-37: Loss of Load Expectation Pie Chart



The graph breaks down probability, or risk, of the the annual days of loss of load based on the distribution of the Monte Carlo simulations performed

A breakdown of LOLE in terms of months per year is provided in the following figure.

Figure A-38: Loss of Load Expectation Monthly Breakdown



Appendix 13. Results – Loss of Load Hours

The following appendix provides more detail regarding the resource adequacy results that are summarized in the main body of this report.

Loss of Load Hours

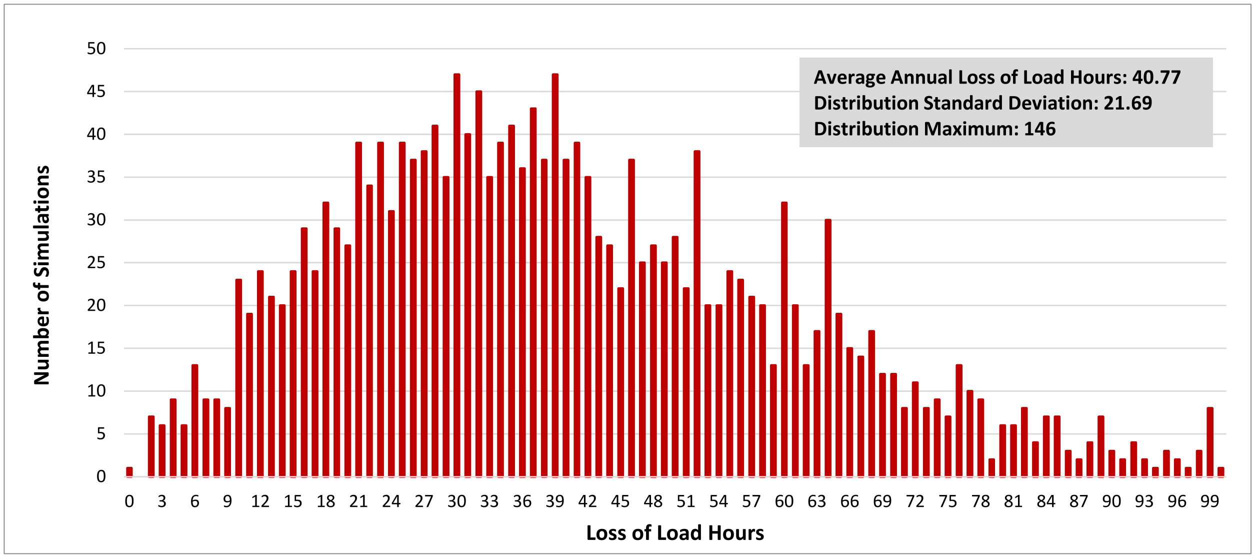
The following table summarizes the LOLH calculations for the current system in FY2023.

Table A-22: Calculated Loss of Load Hours, Current System (FY2023)

Measure	Loss of Load Hours (LOLH)
Average	40.77 Hours / Year
Standard Deviation	21.69 Hours/ Year
Maximum	146 Hours / Year

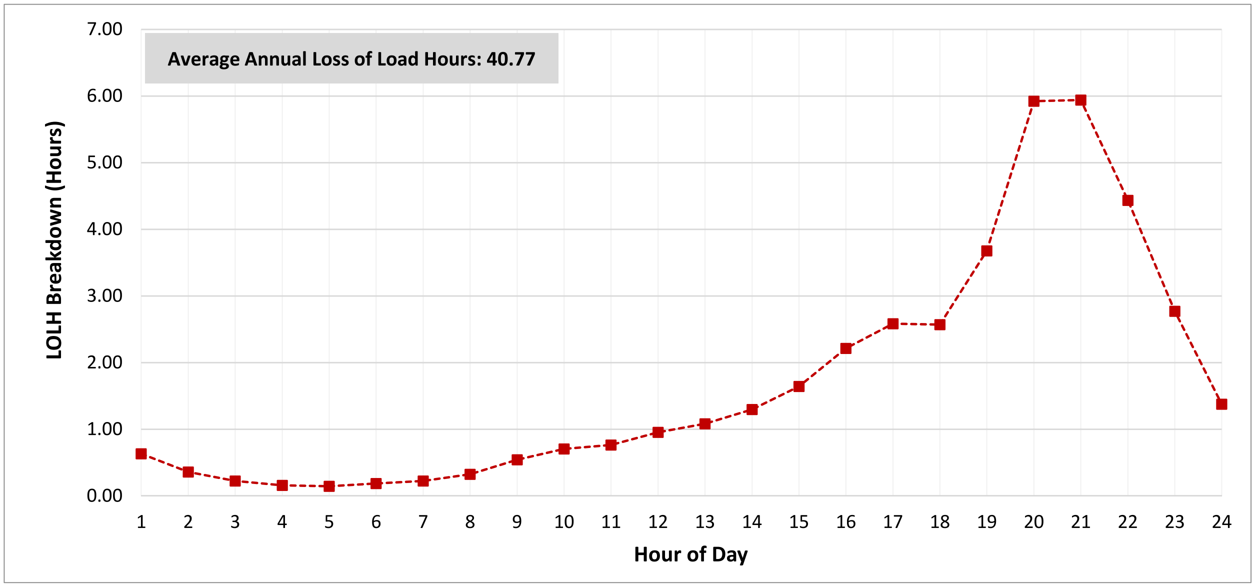
A similar histogram as provided for LOLE in the previous appendix is also provided for LOLH below. One simulation had 146 LOLH, which was the maximum for all simulations performed.

Figure A-39: Distribution of Loss of Load Hour Results



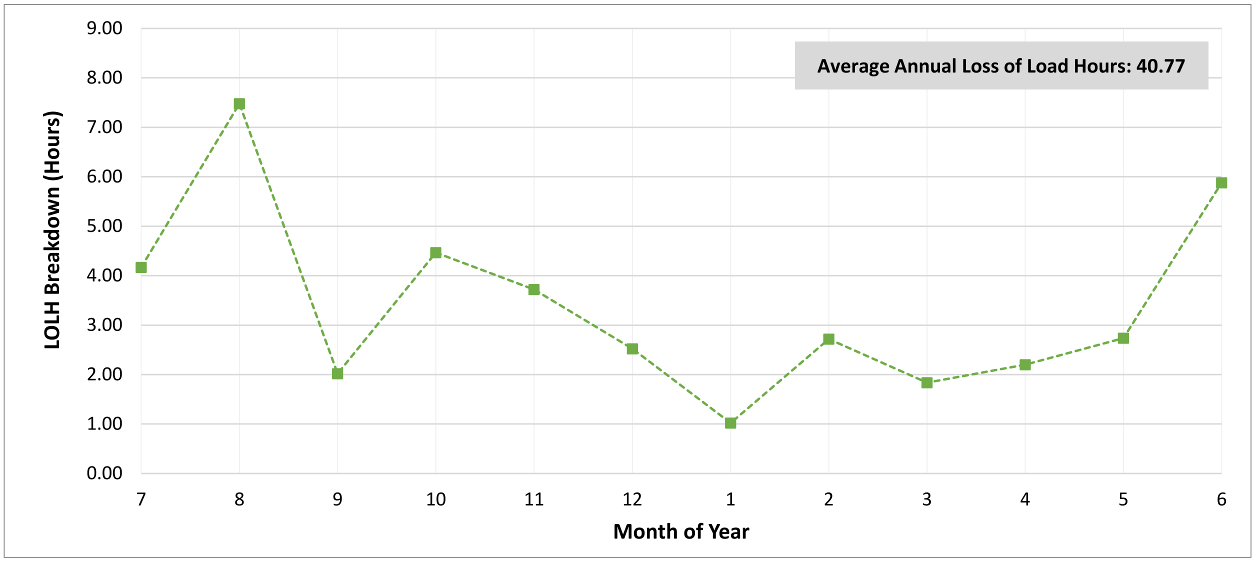
The following figure presents the average number of LOLH for all the simulations, broken out by hour of the day. In the figure, if one were to sum each individual hour, it would total 40.77 LOLH, which is the average annual LOLH for all the simulations. The majority of LOLH are observed during the evening hours, when system load is highest and when solar production is diminished or unavailable to the electric system. Approximately 55% of the observed LOLH in the resource adequacy simulation were observed to occur between 7 p.m. and 11 p.m.

Figure A-40: Calculated Loss of Load Hours Broken Out by Hour of the Day



The figure below shows LOLH broken out by month. LOLH were found to be highest during July, August, and June (2023), primarily because these months correspond to high system load. An additional contribution to LOLH is maintenance outages of large generators. During maintenance outages of large generators, any additional forced outages to other generators could result in LOLH. This is the case for the higher LOLH in October 2022, as this is when EcoEléctrica will be in a maintenance outage.

Figure A-41: Calculated Loss of Load Hours Broken Out by Month of the Year



Appendix 14. Results – Expected Unserved Energy

EUE is the number of megawatt hours (MWh) of load that will not be served in a specific time interval because load exceeds generation. This measure helps to provide an indication on the level of generation shortfall associated with LOLHs. The average annual EUE over all simulations performed is provided in the table below.

Table A-23: Expected Unserved Energy

Measure	Value
Total Average EUE per Year, Averaged Over All Simulations	6,287 MWh

The following figures also provide an illustration of EUE magnitude at different times. The graphs present EUE as a function of hour of the day and month of the year. The graphs generally show that EUE is marginally higher for the time periods where there is a higher risk of LOLH. Note the summing the individual data points below will not equate to the value in the above table. This is because the value in the table reflects the average annual EUE over all simulations, while the data point values below reflect the average number of MWs shortfall just for the hours when loss of load was observed.

Figure A-42: Calculated Expected Unserved Energy Broken Out by Hour of Day

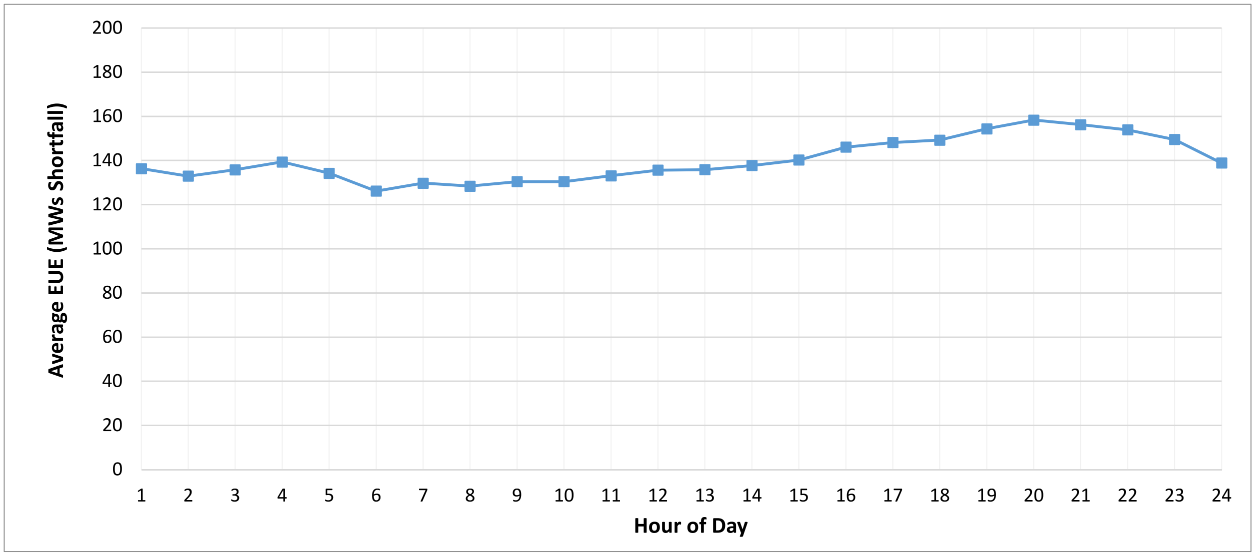
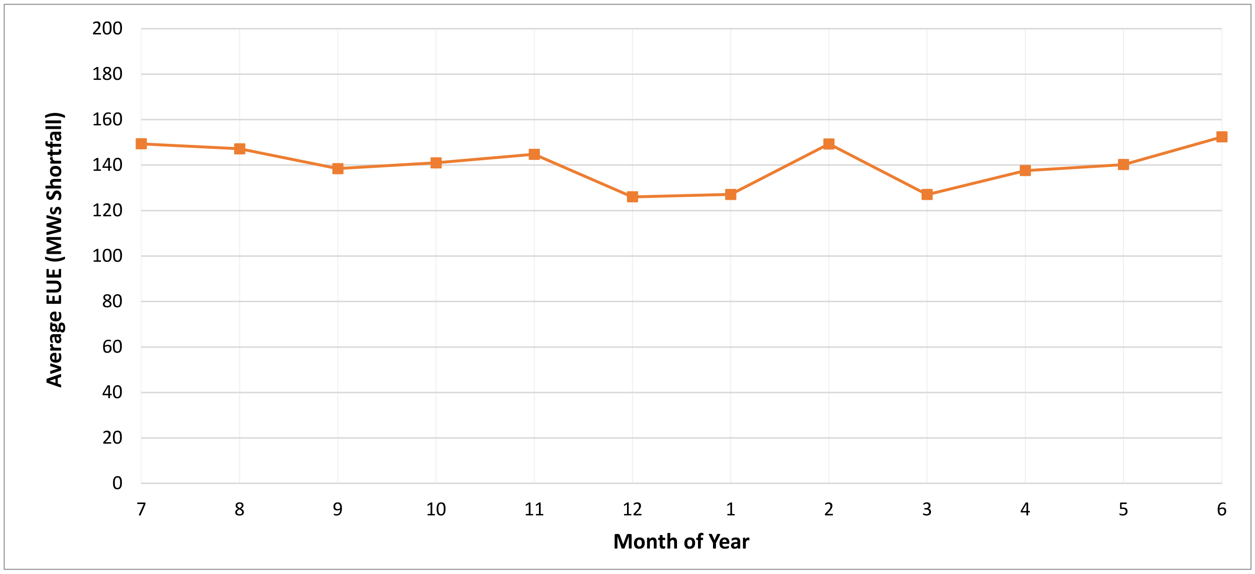


Figure A-43: Calculated Expected Unserved Energy Broken Out by Month of the Year



Appendix 15. Results – Reserve Margin

The average system reserve margin by hour and month was calculated, based on an average over all the simulations performed. This information is illustrated in the following figure. Each input in the figure reflects the ratio of available capacity to load during that hour and month. Available capacity includes both the available capacity of thermal generators and any dependable capacity from operating renewable generators.

Times that correspond to higher LOLH risk are highlighted in various shades of red, the darkest times corresponding to highest LOLH risk. The values in the table are the average over all simulations. In general, times when the ratio of available capacity to load drops below 1.60 correspond to a higher risk of demand not being served in Puerto Rico. This ratio is higher than many other mainland planning regions; however, the uniqueness of Puerto Rico being an island and the fact that a large number of Puerto Rico's generators are unreliable equate to a higher risk of LOLH when the ratio of available capacity to load drops below 1.60.

Figure A-44: Ratio of Capacity to Load

Hour of Day	Month of Year												
	7	8	9	10	11	12	1	2	3	4	5	6	Average
1	1.47	1.45	1.54	1.51	1.56	1.59	1.72	1.59	1.62	1.60	1.52	1.46	**1.55**
2	1.53	1.50	1.59	1.56	1.62	1.66	1.79	1.66	1.68	1.67	1.58	1.51	**1.61**
3	1.58	1.54	1.63	1.60	1.67	1.70	1.83	1.71	1.73	1.73	1.63	1.55	**1.66**
4	1.61	1.57	1.66	1.63	1.69	1.73	1.86	1.74	1.75	1.77	1.67	1.58	**1.69**
5	1.62	1.58	1.68	1.64	1.70	1.74	1.86	1.74	1.76	1.78	1.68	1.60	**1.70**
6	1.61	1.57	1.65	1.61	1.67	1.70	1.82	1.69	1.73	1.75	1.67	1.58	**1.67**
7	1.62	1.57	1.65	1.60	1.64	1.65	1.77	1.64	1.70	1.74	1.66	1.57	**1.65**
8	1.58	1.54	1.63	1.58	1.62	1.65	1.74	1.61	1.66	1.67	1.59	1.51	**1.62**
9	1.53	1.49	1.57	1.53	1.58	1.60	1.69	1.56	1.62	1.62	1.54	1.46	**1.56**
10	1.50	1.46	1.55	1.50	1.54	1.57	1.65	1.53	1.60	1.59	1.51	1.43	**1.54**
11	1.49	1.44	1.52	1.48	1.52	1.56	1.63	1.52	1.58	1.57	1.50	1.43	**1.52**
12	1.48	1.42	1.50	1.45	1.50	1.53	1.59	1.51	1.56	1.55	1.48	1.41	**1.50**
13	1.48	1.41	1.48	1.43	1.48	1.52	1.58	1.50	1.55	1.54	1.47	1.41	**1.49**
14	1.46	1.40	1.46	1.42	1.46	1.52	1.58	1.50	1.55	1.54	1.46	1.40	**1.48**
15	1.44	1.38	1.44	1.40	1.44	1.50	1.56	1.48	1.53	1.52	1.44	1.38	**1.46**
16	1.42	1.36	1.43	1.38	1.41	1.48	1.54	1.46	1.50	1.49	1.42	1.36	**1.44**
17	1.40	1.35	1.42	1.37	1.39	1.45	1.52	1.44	1.47	1.47	1.41	1.36	**1.42**
18	1.39	1.34	1.42	1.37	1.39	1.43	1.51	1.43	1.47	1.46	1.41	1.36	**1.42**
19	1.39	1.33	1.40	1.31	1.30	1.35	1.45	1.40	1.45	1.45	1.40	1.35	**1.38**
20	1.33	1.27	1.36	1.30	1.29	1.34	1.40	1.35	1.37	1.39	1.33	1.30	**1.34**
21	1.30	1.26	1.36	1.31	1.31	1.36	1.43	1.36	1.38	1.39	1.32	1.28	**1.34**
22	1.31	1.28	1.38	1.33	1.35	1.39	1.47	1.39	1.41	1.41	1.34	1.30	**1.36**
23	1.34	1.31	1.42	1.38	1.40	1.44	1.53	1.44	1.46	1.45	1.37	1.33	**1.41**
24	1.40	1.38	1.48	1.45	1.49	1.51	1.62	1.50	1.53	1.52	1.44	1.38	**1.47**
Average	**1.47**	**1.42**	**1.51**	**1.46**	**1.50**	**1.54**	**1.63**	**1.53**	**1.57**	**1.57**	**1.49**	**1.43**	**1.51**

Appendix 16. Results – Historic Available Capacity

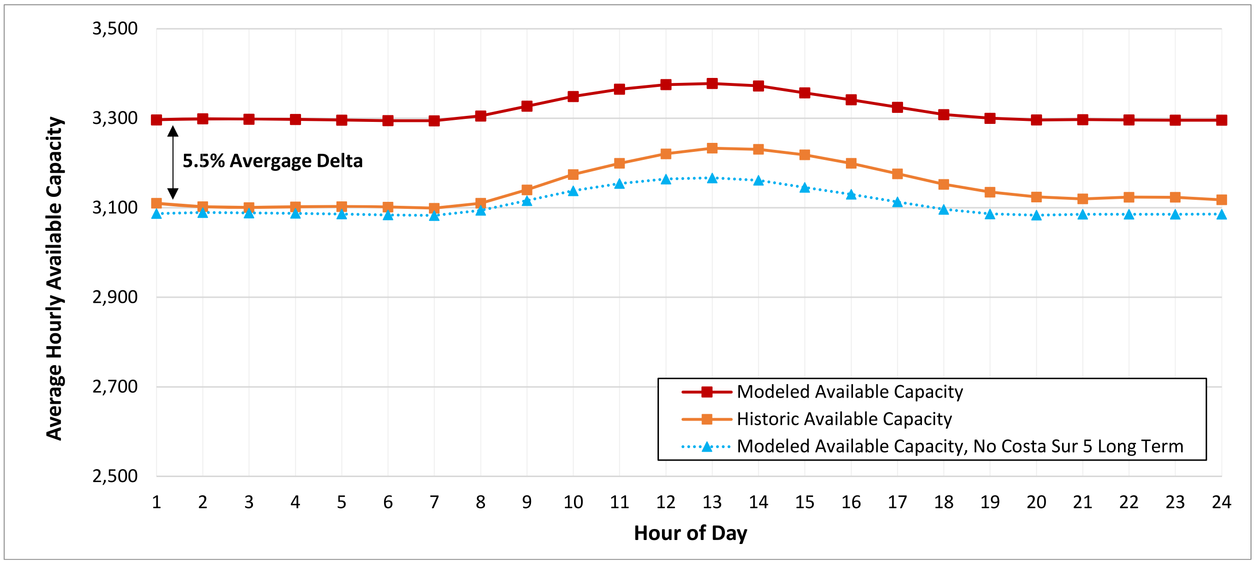
The following figure provides a comparison of the three items listed below:

- Historical available capacity (thermal + renewable generators) for every hour over the last 12 months
- Modeled available capacity (thermal + renewable generators) for the current system, for every hour simulated in FY2023. The modeled available capacity accounts for forced outages, planned outages, and derates.
- Modeled available capacity (thermal + renewable generators) for the current system, but including a long-term loss of Costa Sur Unit 5, for every hour simulated in FY2023 (Costa Sur 5 is modeled as having 350 MW of capacity, derated from the unit nameplate of 410 MW). The modeled available capacity accounts for forced outages, planned outages, and derates.

The data is aggregated and averaged by hour of the day.

As can be seen, the modeled available capacity for the current system is higher than the historical. The current system model shows approximately 200 MW (averaging 5.5%) of additional capacity available for every hour than what was actually experienced historically over the last 12 months. The modeled scenario that considered a long-term outage to Costa Sur Unit 5 better aligns with historical data.

Figure A-45: Comparison of Historical Available Capacity to Model



A key takeaway from the above graph is that the current system model outputs likely portray somewhat more optimistic performance from the perspective of resource adequacy than what has historically been experienced. Historic available capacity has much more closely resembled the scenario considering a long-term outage to Costa Sur Unit 5. There are numerous reasons for the difference in available capacity, including difference between historic and future planned outages, forced outage durations, and a number of generators that are expected to become operational in FY2023 that were not operational over the last 12 months, namely Mayagüez Unit 1 (55 MW) and the Palo Seco Mobile Pack Units 1, 2, and 3 (27 MW each, for a total of 81 MW).

Appendix 17. Effective Load Carrying Capability – Introduction

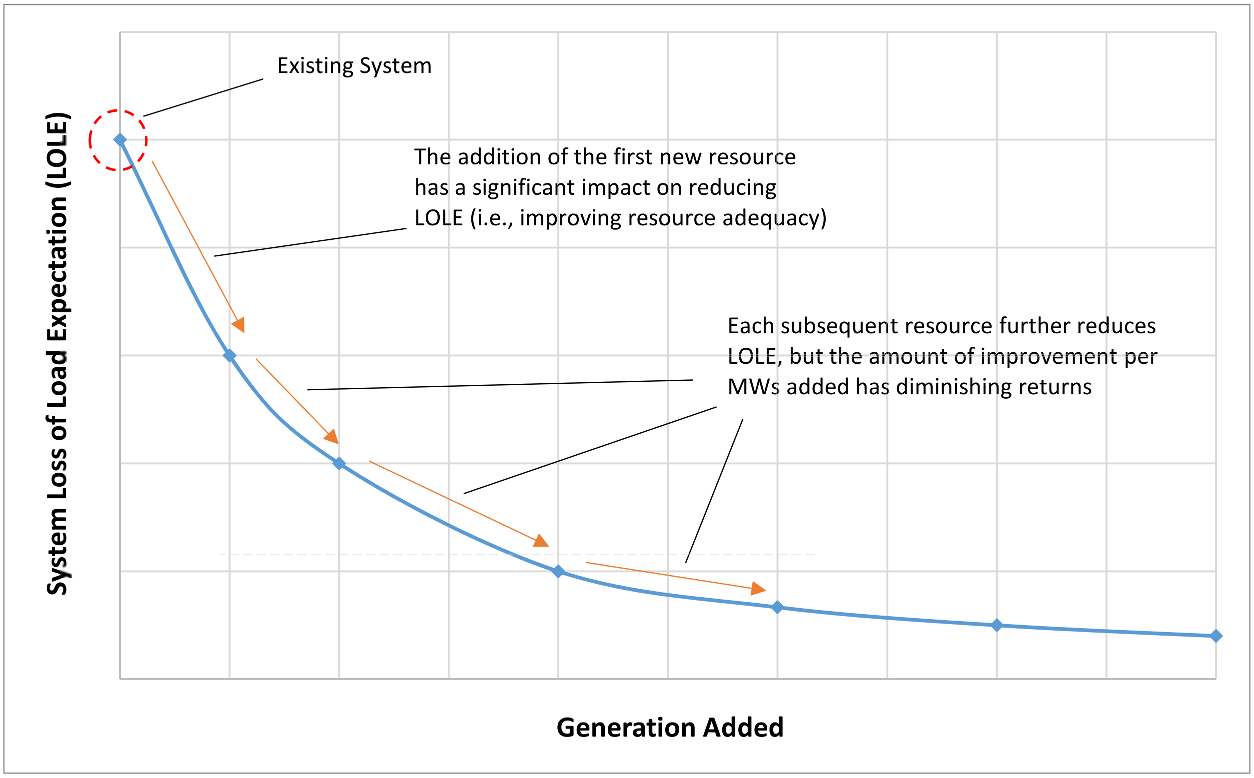
The technical characteristics of different generators can result in the generators providing varying levels of contributions towards resource adequacy. To effectively evaluate different technologies and their contributions towards improving system resource adequacy, a concept called the Effective Load Carrying Capacity (ELCC) of a generator is used. In simple terms, the ELCC of a generator reflects how much the generator is able to contribute towards system resource adequacy. As a single measure, the ELCC allows for quick comparison of resource adequacy contributions of different generators. The use of ELCC as a measure to quantify a generator's contributions towards resource adequacy has increased with the growth in renewable generators, such as solar, wind, and other similar generation technologies, since the variable generation profiles of these generators makes it more of a complex process to quantify the contributions of these generators towards serving system load.

The ELCC of a generator can vary based on a number of variables, including the dispatchability characteristics of the generator. For example, if generation were needed to meet load in the evening, a stand-alone solar power plant would have a lower overall ELCC than a solar power plant paired with an energy storage system. This is due simply to the fact that the stand-alone solar power plant would not be capable of generating much electricity in the evening (since the sun would have nearly set at this time), while the storage system paired to the other solar power plant likely could generate electricity in the evening (provided the storage is sufficiently charged). ELCC will vary from one planning region to another because load characteristics change from region to region.

ELCC is typically expressed as a percentage of what could be provided by a "perfect generator", or a generator that would be available to dispatch every hour of the day, all days of the year. For example, a 100-MW solar generator with an ELCC of 25% would help improve system resource adequacy by an equal amount as a 25 MW perfect generator. An equivalent way to view ELCC is to consider how much system load could be increased with the additional generator such that the system resource adequacy level prior to adding the generator would be equivalent to the resource adequacy level after adding the generator. For example, consider a system with a LOLE equal to 0.10 days/year. A 100 MW solar power plant is added to the system, resulting in the system LOLE to drop to 0.09 days/year. It was then observed that if load were increased by 25 MW, the system LOLE increased back up to 0.10 days/year. In this case, the ELCC of the solar power plant would be equal to 25% (25 MW load increase / 100 MW solar capacity).

It is important to note that the ELCC is a measure of marginal system impact, or the incremental contribution towards resource adequacy. The state of the electrical system from a resource adequacy perspective at the specific time the new generator is added has an impact on the new generator's ELCC. For example, consider the 100 MW solar power plant described above with an ELCC equal to 25% is added to a system. Then, if a second 100 MW is added to the system, the ELCC of the second 100 MW would likely to be less than 25%. The reason for this is because the contributions of additional similar generators towards improving system resource adequacy have diminishing returns. This is illustrated in the following figure, where each dot to the right of the existing system represents additional generators have been added. In the figure, the ELCC of the first new generator would be higher than subsequent generators of similar technology since the amount of LOLE improvement per MW's added reduces with each subsequent addition.

Figure A-46: Marginal ELCC Illustration



Given that there are costs associated with adding new generators, it is important for system planners to assess the appropriate balance between the desired system LOLE target and system cost, especially since the benefits associated with additional returns diminishes with each additional MW added.

The performance of electric generators in Puerto Rico is currently very poor; thus, there often is not sufficient generation to meet load. As a result, additional MWs of generation in Puerto Rico would result in significant benefits to overall system resource adequacy. Additionally, improvements/modifications to the existing generators in Puerto Rico that improved the generators' resource adequacy would also help improve system resource adequacy. Improving the resource adequacy of the existing generators would increase the ELCC of those generators.

Appendix 18. Effective Load Carrying Capability – Calculation Methodology

ELCC for a generating resource provides the resource adequacy improvement contribution of that generator to the system. Specifically, the ELCC of a generating resource is determined by identifying the size of a perfect capacity generator that yields the same resource adequacy improvement as was achieved with the addition of the resource in study.

The resource adequacy benefit (ELCC) of a generating resource is calculated by first adding the new generator to the study system and noting the improvement to system resource adequacy. Next, a “perfect generator”, which is defined as a generator with capacity that is available 100% of the year, is added to the original study system, sized such that the same resource adequacy improvement is achieved. The ELCC is the perfect generator size divided by the new generator size. The following figure provides a step-by-step example of the calculation.

Figure A-47: ELCC Example Calculation

Current System + X MWs = New System A
$LOLE_{Current\ System}$ = 0.15 days/year, $LOLE_{New\ System\ A}$ = 0.10 days/year

The resource "X" above represents a new generator's nameplate capacity.
For example, X might represent 100 MW nameplate for a solar project.

Current System + Z MWs = New System B
$LOLE_{Current\ System}$ = 0.15 days/year, $LOLE_{New\ System\ B}$ = 0.10 days/year

The resource "Z" above represents a new perfect generator.
For example, Z might represent a 30 MW perfect generator.

Z/X = ELCC %

The ELCC is equal to the capacity of the perfect generator divided by the nameplate capacity of the new generator. In this example, the ELCC of the solar project would be 30%, as the 100 MW solar generator would contribute an equal amount to system reliability as a 30 MW perfect generator.

Understanding the varying ELCC values of technologies can assist resource planners in resource adequacy decision-making. The ELCC value for a given technology must be calculated each time a generator is added to the system, since it will change with each additional generating resource.

Appendix 19. Sensitivity Analysis – Introduction

A number of different sensitivity analyses are performed for this report. The sensitivity analyses performed reflect changes starting from the current system. A list of the different analyses performed is provided below.

- **Current System.** Baseline model based on system operation in FY2023. This scenario reflects the baseline comparison to all of the additional sensitivity analyses listed below. Results from this scenario are described in Appendix 12 through Appendix 16.
- **Long-Term Loss of a Large Generator.** This sensitivity simulation reflects the current system model, but with a large generator out of service for the entire year. For this simulation, Costa Sur Unit 5 is assumed to be out of service. This simulation was performed to illustrate the impact of losing a large generator for a long-term period, similar to what was experienced in the beginning of 2020 when the earthquakes in southern Puerto Rico resulted in significant damage to the Costa Sur power plant. Note that given the high forced outage rates and relatively poor operating condition of the power plants in Puerto Rico, the risk of a long-term loss of a large generator is not a low probability risk.
- **Meeting Industry LOLE Benchmarks.** This sensitivity simulation determines how much additional ‘perfect’ generation capacity would need to be added to the Puerto Rico electrical system in order for a LOLE target of 0.10 days/year to be met. For reference, ‘perfect’ generation capacity is equivalent to a generator that can operate 100% of the time, for every hour of the year. Equivalently, it can be considered as a constant MW reduction in load for every hour of the year. The goal of this simulation is to quantify the generation shortfall in Puerto Rico. While no generator is “perfect,” identifying how many MW of perfect capacity are needed helps to provide a best-case estimate of what would be required in terms of generation (or load reduction) to bring Puerto Rico in line with a 0.10 days/year LOLE target.
- **New Solar Addition.** This sensitivity simulation illustrates the impact of adding new solar generation to the current system model in varying MW levels. For this sensitivity, all added solar is assumed to be standalone solar, meaning none of the MW are considered to be paired with energy storage. Separate sensitivity simulations which consider energy storage are listed below.
- **New Standalone BESS Addition.** This sensitivity simulation illustrates the impact of adding standalone battery energy storage systems (BESS) to the current system model in varying MW levels.
- **New Solar Paired with BESS Addition.** This sensitivity simulation illustrates the impact of adding new solar generation paired with BESS to the current system model in varying MW levels.
- **New Flexible Thermal Resources.** This sensitivity simulation illustrates the impact of adding new flexible thermal resources (i.e., engines, combustion turbines) to the current system model in varying MW levels.
- **New Demand Response Resources.** This sensitivity simulation illustrates the resource adequacy impact of adding demand response (DR) resources (i.e., short-term reductions in system load) to the current system model in varying MW levels.
- **Energy Efficiency Load Reduction.** This sensitivity simulation illustrates the resource adequacy impact of various levels of energy efficiency initiatives that result in system electrical demand reductions.

Appendix 20. Sensitivity Analysis – Comparison of Scenario Results

The following table summarizes the LOLE and LOLH model results for the various sensitivity analyses performed.

Table A-24: Calculated Resource Adequacy Risk Measures – All Sensitivity Cases

<table>
<tr><th colspan="2">Scenario</th><th>Loss of Load Expectation (LOLE), Days / Year</th><th>Loss of Load Hours (LOLH), Hours / Year</th></tr>
<tr><td colspan="2">Current System</td><td>8.81</td><td>40.77</td></tr>
<tr><td colspan="2">Current System Without Costa Sur Unit 5</td><td>28.08</td><td>155.06</td></tr>
<tr><td rowspan="13">Current System +</td><td>675 MW of ‘Perfect Capacity’</td><td>0.1</td><td>0.36</td></tr>
<tr><td>420 MW of Solar PV</td><td>8.29</td><td>30.58</td></tr>
<tr><td>845 MW of Solar PV</td><td>8.17</td><td>28.43</td></tr>
<tr><td>100 MW Standalone BESS (4 Hour)</td><td>5.79</td><td>27.71</td></tr>
<tr><td>200 MW Standalone BESS (4 Hour)</td><td>3.87</td><td>19.21</td></tr>
<tr><td>420 MW Solar PV + 100 MW Solar-Paired BESS (4 Hour)</td><td>5.01</td><td>20.22</td></tr>
<tr><td>845 MW Solar PV + 200 MW Solar-Paired BESS (4 Hour)</td><td>3.12</td><td>12.40</td></tr>
<tr><td>100 MW Flexible Thermal Resource</td><td>5.15</td><td>22.56</td></tr>
<tr><td>200 MW Flexible Thermal Resource</td><td>3.01</td><td>12.55</td></tr>
<tr><td>25 MW Demand Response (8 Hour)</td><td>7.77</td><td>35.75</td></tr>
<tr><td>50 MW Demand Response (8 Hour)</td><td>6.62</td><td>30.17</td></tr>
<tr><td>0.25% Energy Efficiency (Load Reduction)</td><td>8.56</td><td>39.77</td></tr>
<tr><td>0.50% Energy Efficiency (Load Reduction)</td><td>8.16</td><td>37.36</td></tr>
<tr><td colspan="2">Industry Benchmark Target</td><td>0.1</td><td>—</td></tr>
</table>

Appendix 21. Sensitivity Analysis – Long-Term Loss of a Large Generator

A separate sensitivity simulation was performed exploring the potential impact of a long-term outage to a baseload generator on Puerto Rico's resource adequacy. The simulation considered a scenario where there was a one-year outage to Costa Sur Unit 5. Other variables associated with the sensitivity scenario were unchanged from those discussed in previous sections of this report (i.e., they were kept consistent with the "Current System" scenario). The simulated loss of Costa Sur Unit 5 resulted in a sharp increase in days of loss of load (LOLE) and LOLH.

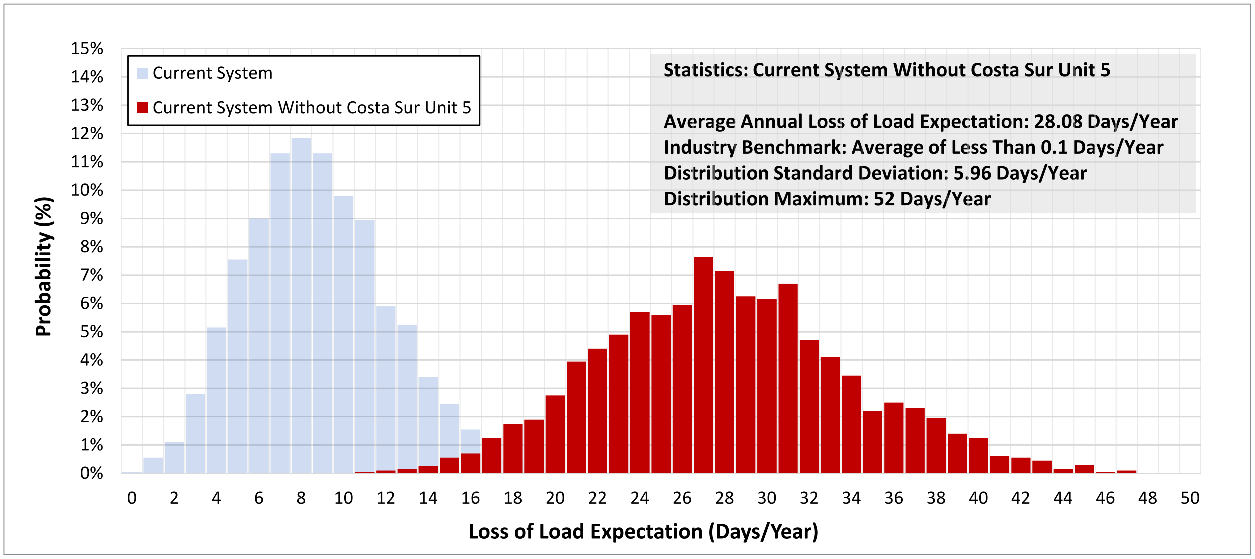
The results clearly indicate that a single, long-term outage to a baseload generator can have a significantly detrimental impact to the island's resource adequacy performance. A comparison of the Current System scenario to this sensitivity case is provided in the table below. As can been seen, both LOLE and LOLH increase by roughly a factor of three to four. The results illustrate how little margin Puerto Rico has with respect to generation resource adequacy.

Table A-25: Calculated Resource Adequacy Risk Measures – Long-Term Loss of Large Generator

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System, but with Costa Sur Unit 5 Out for Entire Year	28.08 Days / Year	155.06 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

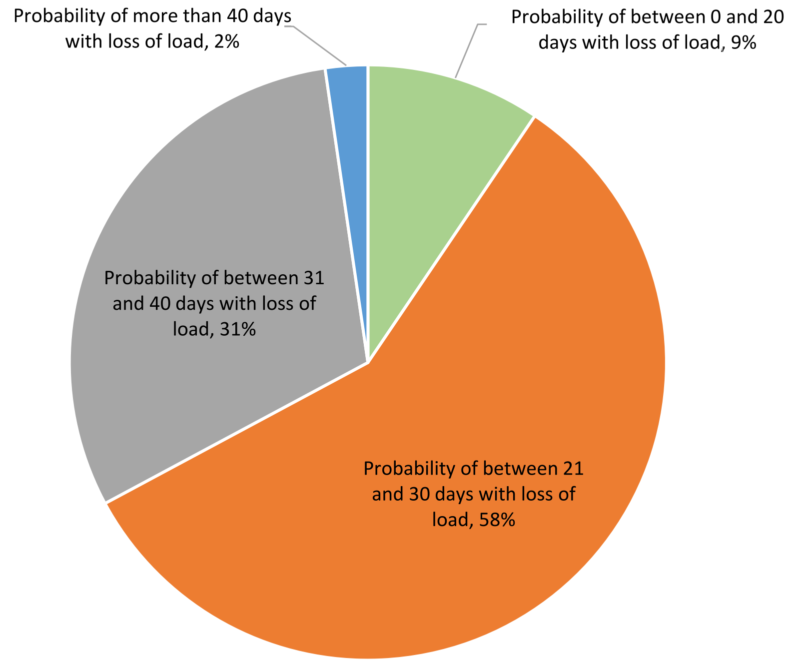
The following figure presents the LOLE results of the simulations for this sensitivity scenario presented as a probability distribution. The figure illustrates the width of the distribution of simulations. While the average LOLE of the simulations was just above 28 days/year, a significant number of simulations had both more and less than this average.

Figure A-48: Loss of Load Expectation Probability Chart – Long-Term Loss of a Large Generator



The LOLE results are also aggregated into a pie chart, which is provided in the following figure. As can be seen, just under 90% of simulations have more than 20 days of loss of load.

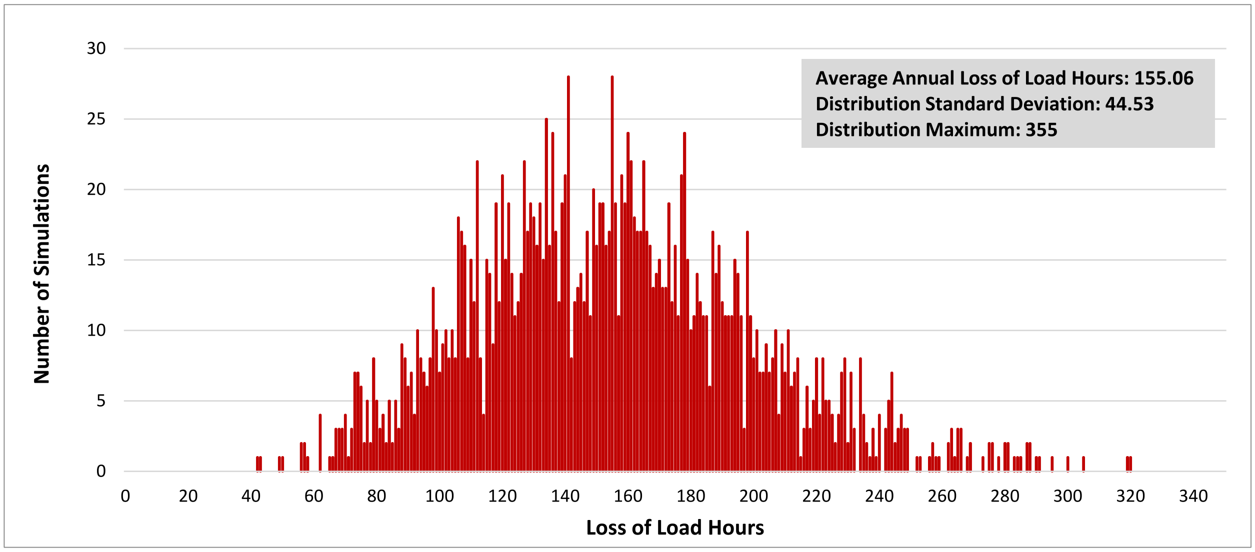
Figure A-49: Loss of Load Expectation Pie Chart – Long-Term Loss of a Large Generator



The graph breaks down probability, or risk, of the the annual days of loss of load based on the distribution of the Monte Carlo simulations performed

LOLH results of the sensitivity analysis are also provided in a histogram, shown below. The results indicate a wide distribution in LOLH, with a significant number of simulations with a very high number of LOLH.

Figure A-50: Distribution of LOLH Results – Long-Term Loss of a Large Generator



Appendix 22. Sensitivity Analysis – Perfect Capacity Estimated Equivalency

An analysis was performed to determine how much additional 'perfect' capacity[31] would need to be added to the Puerto Rico electrical system to achieve a LOLE target of 0.10 days/year. The analysis was completed by adding various amounts of perfect capacity to the resource adequacy model and re-running the analysis. The analysis was complete once the amount of perfect capacity that resulted in the system LOLE equaling 0.10 days/year was determined. The results of the simulation determined that 675 MW of perfect capacity would result in a LOLE of 0.10 days/year. Results are summarized in the following table.

Table A-26: Calculated Resource Adequacy Risk Measures – Perfect Capacity Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System + **675 MW** of Perfect Capacity	0.10 Days / Year	0.36 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

Given that no generation technology can operate as a perfect generator, the actual amount of capacity required for the system to meet a 0.10 days/year LOLE target would be somewhat higher than the 675 MW identified above. Additionally, it varies by generator technology type. The uniqueness of the resource adequacy contributions of different technologies is driven by generator capacity factor, energy availability, maintenance, plant outages, and dispatchability.

Modeling results indicate that in Puerto Rico, 675 MW of perfect capacity is required to obtain the 0.1 days per year industry benchmark LOLE target.

An underlying assumption around perfect capacity is that it operates at a 100% capacity factor. For 675 MW of perfect capacity, this would be equivalent to 5,913,000 MWh of annual generation. For illustrative purposes, a high-level comparison of technology capacity factors required to achieve 5,913,000 MWh of energy is provided in the following table. Note that even with equivalent annual generation, non-dispatchable generation technologies may still fall short of helping the system achieve a 0.1 days / year LOLE target without storage resources to shift energy to needed time periods.

[31] Perfect generation capacity is always fully available. From a modeling perspective, MWs of perfect capacity are equivalent to the same number of MWs as a reduction in hourly system load. Perfect capacity is theoretical in nature and not based on a specific generation technology type; however, if it were derived from intermittent sources, there would need to be sufficient energy storage such that it was fully dispatchable for every hour.

Table A-27: Capacity Factor Comparison for Various Technologies

Scenario	Annual Generation (MWh)	Capacity Factor (%)
675 MW of Perfect Capacity	5,913,000	100
2,935 MW of Solar PV	5,913,000	23
3,068 MW of Wind	5,913,000	22
711 MW of Flexible Capacity	5,913,000	95

The following figures provide more detail regarding the results of the analysis, particularly with respect to LOLH on both an hourly and monthly basis. The figures both compare the current system to the system with the additional 675 MW of perfect generation capacity. As can be seen, the addition of the 675 MW significantly improves the overall electrical system from the perspective of generation resource adequacy.

Figure A-51: Comparison of Loss of Load Hours Broken Out by Hour of the Day

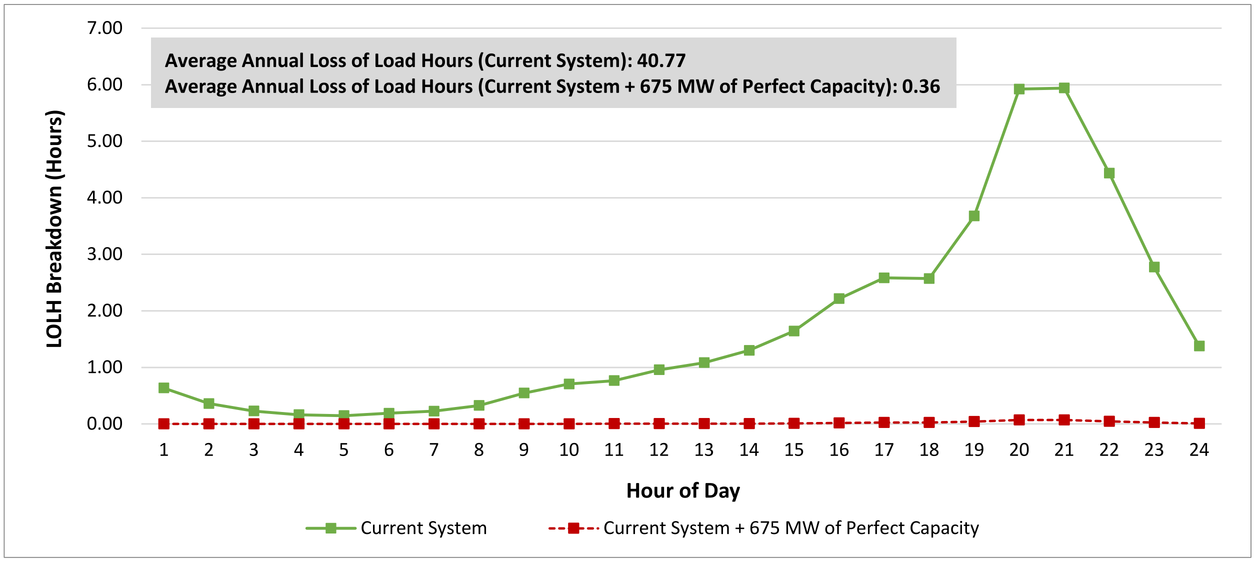
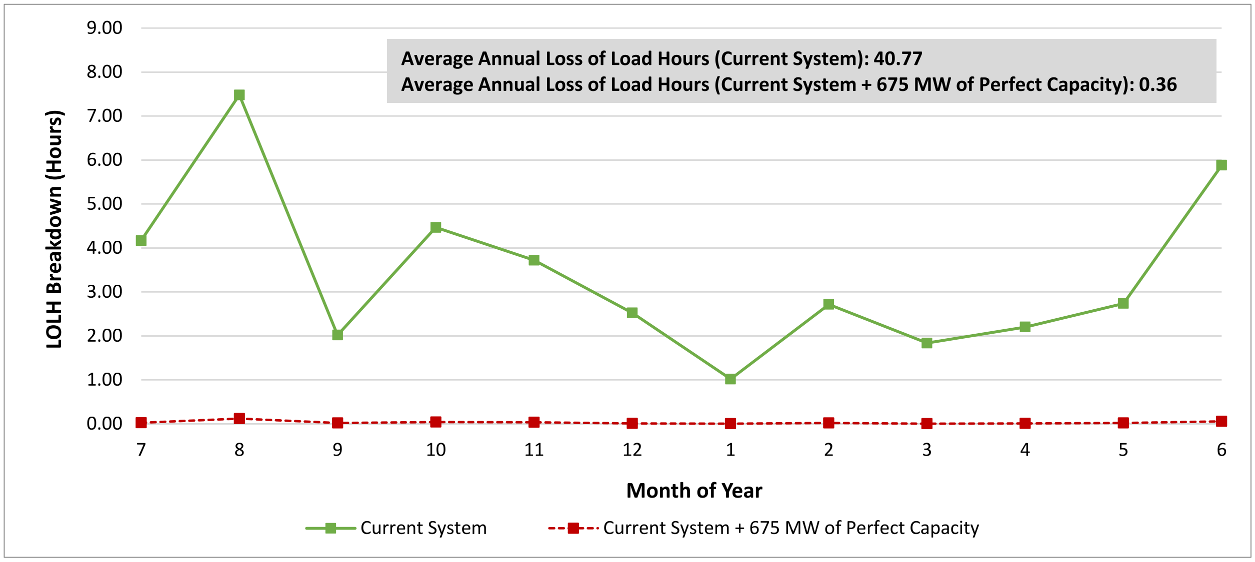


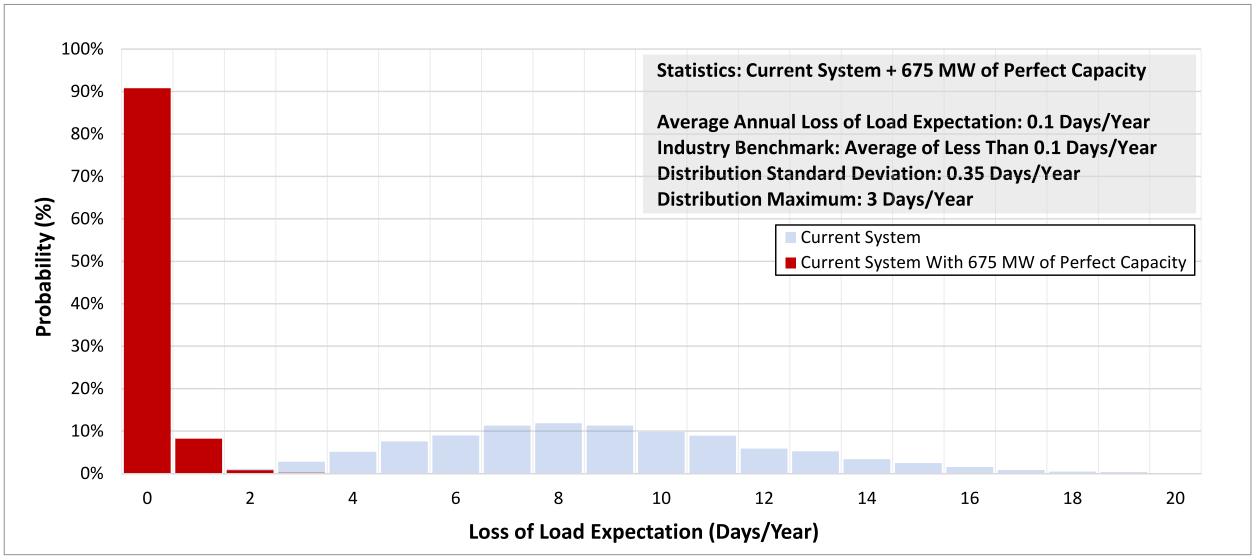
Figure A-52: Comparison of Loss of Load Hours Broken Out by Month of the Year



The figure below presents the aggregated LOLE results of the simulations for the scenario with the additional 675 MW of perfect capacity included in the overall generation portfolio. The graph presents the probability distribution of the simulation output. Just approximately 9% of the simulations performed were found to have days where there was loss of load. Superimposed on the figure is the distribution from the current system simulations for comparison.

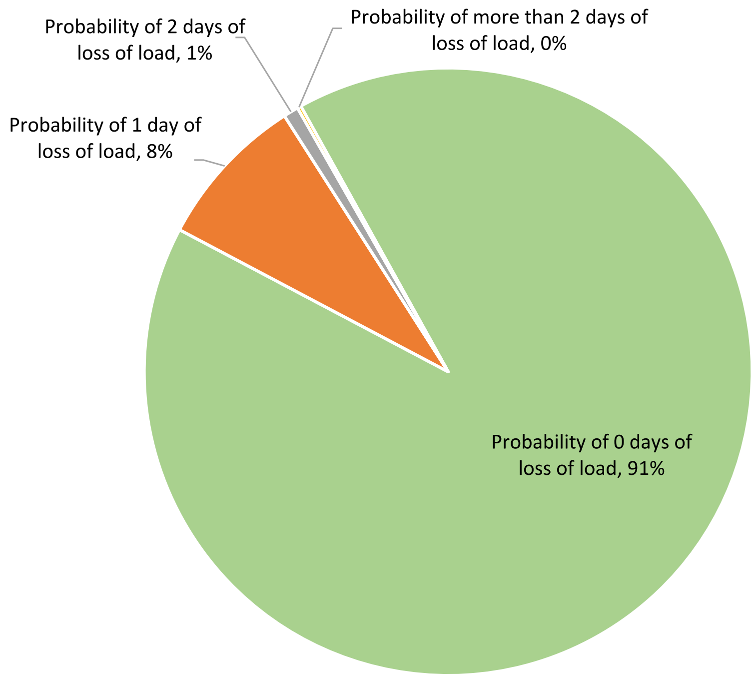
This information can be further visualized in the chart that follows.

Figure A-53: Loss of Load Expectation Probability Chart – Perfect Capacity Addition



The information shown above can be further visualized in the pie chart that follows.

Figure A-54: Loss of Load Expectation Pie Chart – Perfect Capacity Addition



The graph breaks down probability, or risk, of the the annual days of loss of load based on the distribution of the Monte Carlo simulations performed

Appendix 23. Sensitivity Analysis – Additional Solar Results

Two sensitivity scenarios were evaluated to assess potential resource adequacy contributions of additional solar generation in Puerto Rico. The scenarios added solar energy to the current system in two quantities: 420 MW and 845 MW. The value of 845 MW was chosen because this is the expected amount of solar energy that is projected to be added to Puerto Rico as a result of the PREPA Tranche 1 renewable procurement. A value of 420 MW was analyzed because it represents approximately half of the Tranche 1 MW level and thus provides a basis for comparison. Note that these scenarios do not include energy storage as they seek to only investigate the impact of additional solar. Both standalone energy storage and energy storage paired with solar are investigated in other sensitivity analyses documented in later appendices of this report.

As illustrated in the table below, the first 420 MW of solar added to the current system decreases LOLE from 8.81 days/year to 8.29 days/year, which is a 6% improvement in LOLE. An additional 425 MW of solar (to the expected Tranche 1 level of 845 MW) further reduces LOLE to 8.17 days/year, which is approximately a 7% improvement from the current system, but only a 1% improvement from a system already with 420 MW of solar. Solar additions to the current system provided a greater resource adequacy contribution toward reducing the LOLH rather than LOLE. For instance, the first 420 MW of solar added to the system decreased the LOLH from 40.77 hours/year to 30.58 hours/year, which is a 25% reduction. The second 425 MW of solar (to a level of 845 MW total) further decreased the LOLH to 28.43 hours/year, which is a 7% additional reduction (totaling a 30% reduction from the current system).

Table A-28: Calculated Resource Adequacy Risk Measures – Solar PV Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System + 420 MW of Solar PV	8.29 Days / Year	30.58 Hours / Year
Current System + 845 MW of Solar PV	8.17 Days / Year	28.43 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

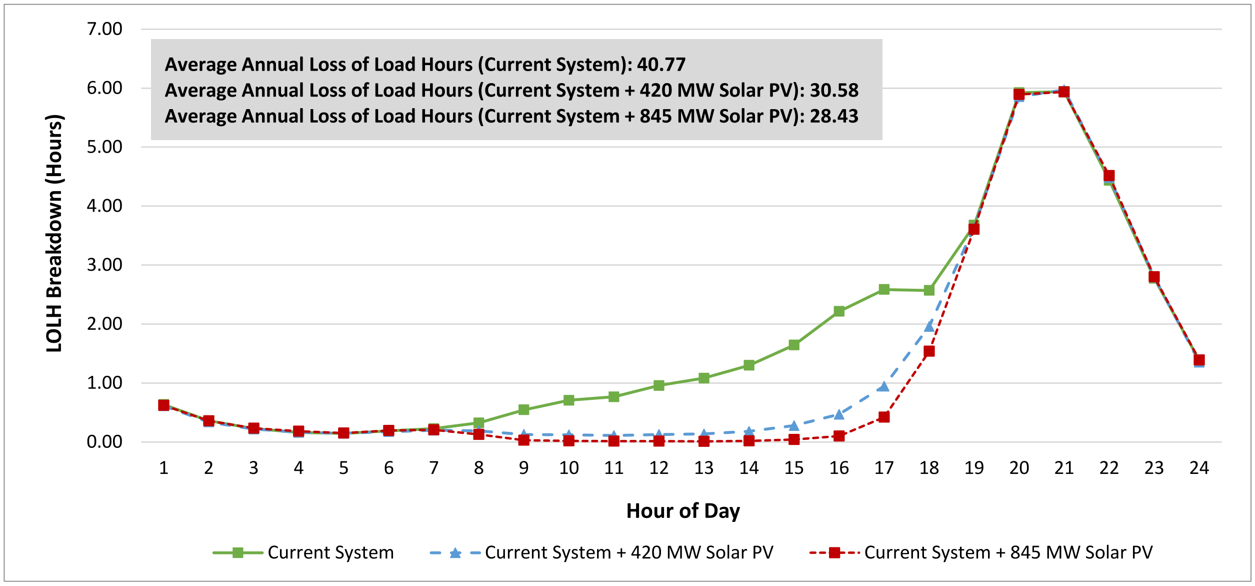
The difference between the relatively low LOLE improvement versus the more robust improvement in LOLH stems mainly from a combination of when solar power plants generate and when the electrical system is at greatest risk for loss of load. During the middle of the day, solar can contribute a great deal of MWs towards meeting system load; however, during the evening (after the sun has set), additional solar is not able to contribute towards meeting system because solar generation will be zero at this time. In Puerto Rico, the risk of loss of load during the middle of the day is pronounced; however, the highest risk period is in the evening because this is when system load is highest. As a result, if there was a generation shortfall event that spanned an entire day (i.e., a forced outage to a large thermal generator), additional solar would help to mitigate potential loss of load during the middle of the day, but both the current system and a system with additional solar would be equally as challenged to meet load in the face of the generation shortfall event in the evening after the sun had set. In this example, the additional solar might help to shorten the length of a loss of load period (i.e., reduce the total LOLH) by helping the system to meet load during the day, but it would not be able to prevent the loss of load event from still

occurring in the evening, which means there still would be a day where there was loss of load (hence the small reduction in LOLE).

The following figure compares the timing of the average annual loss of load hours for each hour of the day for the current system versus the two solar additional cases. The figure clearly illustrates that additional solar is able to help mitigate LOLH during the middle of the day, but not during the evening.

A second point to note is the diminishing returns in terms of resource adequacy improvement as a result of adding solar in various MW levels. This can be seen in the following figure, specifically by observing the distance between the current system line (green), the 420 MW of additional solar line (blue), and the 845 MW of additional solar line (red). The blue and red lines are much closer together than the green line, which indicates that the amount of resource adequacy improvement from going from 420 MW of solar to 845 MW of solar is small compared to the improvement from adding any amount of additional solar to the current system. The reason for this is because the addition of 420 MW of solar to the current system already reduces LOLH during the middle of the day to nearly zero; thus, additional solar on top of the 420 MW can only minimally further improve system LOLH.

Figure A-55: Comparison of Loss of Load Hours by Hour – Solar PV Addition



Appendix 24. Sensitivity Analysis – Additional Standalone BESS Results

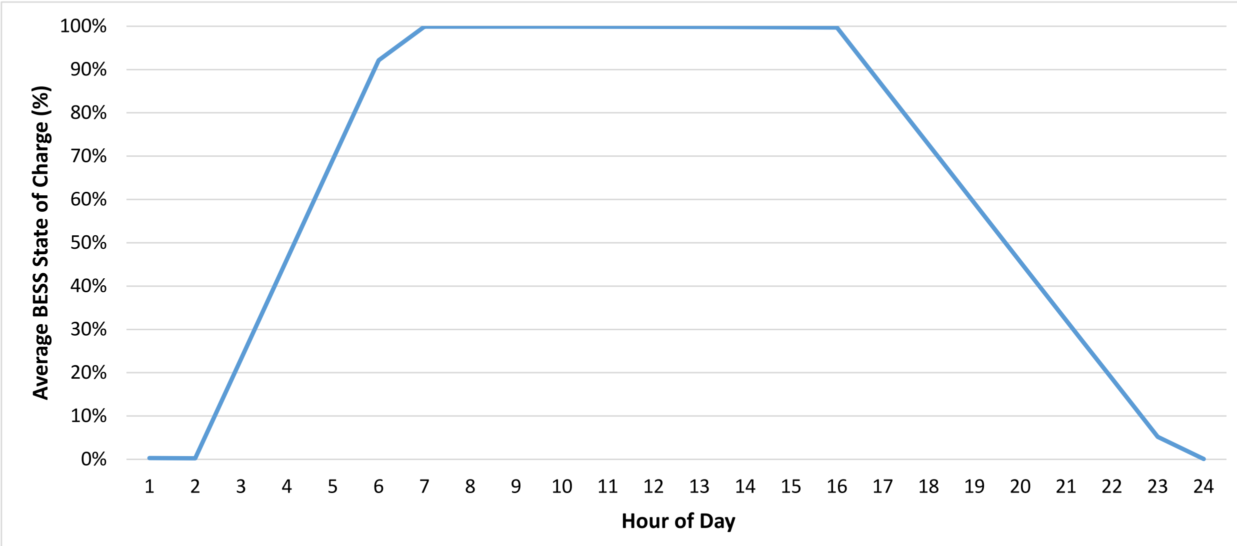
This sensitivity evaluates the impact of adding standalone BESS to the current system. For this sensitivity, no additional solar is added to the current system. Two sensitivity scenarios with varying amounts of standalone BESS were performed. The first scenario adds 100 MW of standalone 4-hour duration BESS (400 MWh total), while the second scenario doubles that amount for a total of 200 MW of standalone 4-hour duration BESS (800 MWh total).

For this scenario, the round-trip efficiency of the BESS is assumed to be 85%. Typical hourly dispatch of the BESS is modeled such that discharge occurs throughout the evening to help meet peak load, with the BESS modeled as being depleted around midnight. Charging of the BESS primarily takes place during the early morning hours, when system load is lowest. Whenever there is an emergency situation, defined as a period where load is greater than available capacity, the model forces BESS resources to inject available energy to meet load demand. If the shortfall in available system capacity is greater than what the BESS is able to inject at that hour, or if the BESS does not have sufficient charge, the BESS resources inject what they are able to in order to minimize the MW shortfall.

In contrast to solar-paired BESS, standalone BESS has the benefit of being able to charge from the grid at any time during the day, capturing surplus energy during times when available capacity is high and energy demand is low (i.e., nighttime in Puerto Rico). Since it can be fully charged earlier in the day than solar-paired BESS, it can be dispatched to help mitigate emergency MW shortfall situations that occur earlier in the day, when a solar-paired BESS might otherwise not yet be fully charged. In contrast, because standalone BESS charges from energy from the generating resources that are operating at that time, if standalone BESS is charging during the early morning, it is primarily charging from thermal generators, not renewable generators. Additionally, if standalone BESS is mostly charged before the sun rises, then it could not be used as a tool to help mitigate potential solar power plant curtailment. We recommend both standalone and solar-paired BESS be considered as potential candidate resources for further analysis in the future IRP process.

The figure below shows the average state of charge by hour of the day for the standalone BESS over all simulations performed. As shown, the BESS is primarily charging overnight between 2 and 7 a.m. On average, BESS are not utilized during the majority of daytime hours (unless an emergency situation occurs during this time) and start discharging at 4 p.m. to help the system during the evening peak.

Figure A-56: Standalone BESS Average State of Charge by Hour (100 MW and 200 MW BESS)



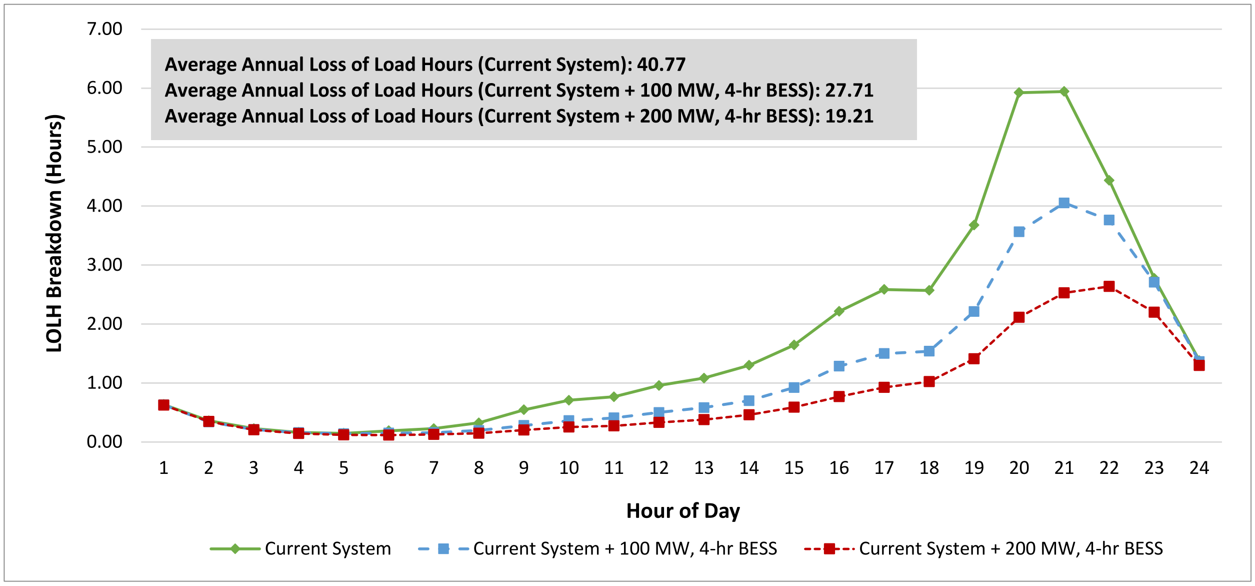
The table below shows the results of these two sensitivity cases along with the current system results for comparison. As compared to the current system, the addition of 100 MW of standalone BESS reduces both LOLE and LOLH by approximately 34%; the addition of 200 MW of standalone BESS reduces both LOLE and LOLH by approximately 56%.

Table A-29: Calculated Resource Adequacy Risk Measures – Standalone BESS Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System + 100 MW Standalone BESS (4 Hour Duration)	5.79 Days / Year	27.71 Hours / Year
Current System + 200 MW Standalone BESS (4 Hour Duration)	3.87 Days / Year	19.21 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The addition of standalone BESS results in nearly the same improvement to both LOLE and LOLH for a given scenario. This is because standalone BESS can contribute to system capacity nearly all times of the day, with the only limitation being the state of charge. Given that 55% of the observed LOLH in the current system scenario occurred between 7 p.m. and 11 p.m., standalone BESS has a positive impact on system resource adequacy due to its ability to support the system at night. The figure below shows the average LOLH for all the simulations for the three scenarios. As shown, the standalone BESS help reduce the incidence of LOLH during the day and nighttime hours.

Figure A-57: Comparison of Loss of Load Hours by Hour – Standalone BESS Addition



Appendix 25. Sensitivity Analysis – Additional Solar and Paired BESS Results

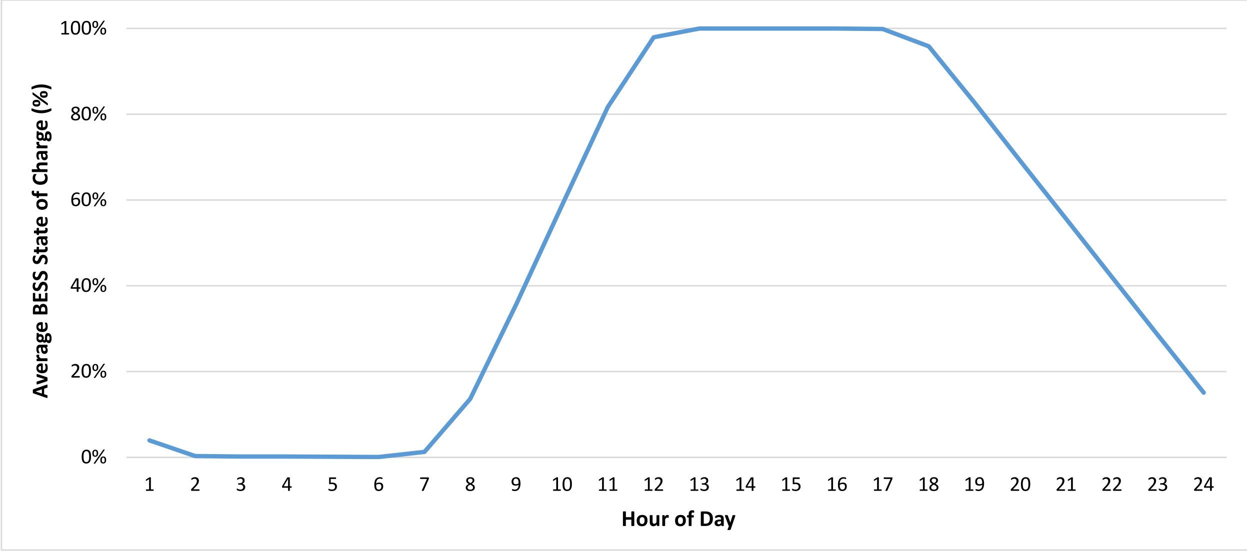
This sensitivity evaluates the impact of combining both solar PV and BESS. In this sensitivity, the BESS is modeled as paired with the solar PV, meaning that it is only allowed to charge from the solar generation. Two sensitivity scenarios with varying amounts of new generating resources were performed. The first scenario adds 420 MW of solar PV paired with 100 MW of 4-hour duration BESS (400 MWh total). The second scenario doubles these amounts for a total of 845 MW of solar PV paired with 200 MW of 4-hour duration BESS (800 MWh total). Note that these two scenarios represent half and the full addition of new generating resources as planned under PREPA's renewable Tranche 1 projects.[32]

For this scenario, the round-trip efficiency of the BESS is assumed to be 85%. Typical hourly dispatch of the BESS is modeled such that discharge occurs throughout the evening to help meet peak load, with the BESS modeled as being depleted around or shortly after midnight. Charging of the BESS is from the solar power plants; thus, charging only occurs during the day. Whenever there is an emergency situation, defined as a period where load is greater than available capacity, the model forces BESS resources to inject available energy to meet load demand. If the shortfall in available system capacity is greater than what the BESS is able to inject at that hour, or if the BESS does not have sufficient charge, the BESS resources inject what they are able to in order to minimize the MW shortfall.

In contrast to standalone BESS, solar-paired BESS can only charge from any excess available energy from the solar resources. Because of this, any generation from these BESS would be considered renewable generation and would contribute towards Puerto Rico's renewable portfolio standards. The figure below shows the average state of charge by hour of the day for the solar-paired BESS. As shown, the BESS begin to charge as the sun rises and are typically fully charged in the model by noon. BESS then start discharging at 6 p.m. as the sun sets to support the electrical system during the evening peak.

[32] Tranche 1 of PREPA's renewable resource procurement process currently accounts for 20 MW of standalone BESS. This sensitivity analysis excludes that small generation amount to understand the impact of solar-paired BESS. Standalone BESS were evaluated in the previous sensitivity analysis.

Figure A-58: Solar-Paired BESS Average State of Charge by Hour (100 MW and 200 MW BESS)



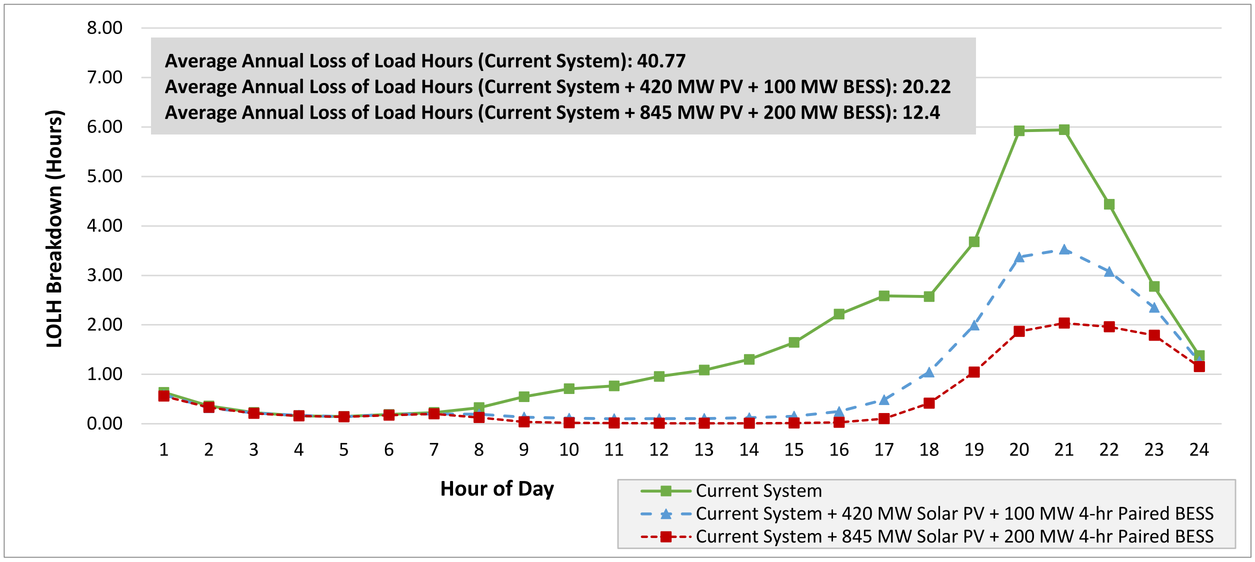
The table below shows the results of the two sensitivity scenarios, along with the current system results for comparison. As compared to the current system, the addition of 420 MW of solar PV paired with 100 MW of BESS reduces LOLE by 43% and LOLH by 50%, while 845 MW of solar PV paired with 200 MW of BESS reduces LOLE by 65% and LOLH by 70%. Similar to what was observed in the solar-only sensitivity scenario (see Appendix 23), the combination of new resources has a greater impact on LOLH versus LOLE because of the contributions of the solar resources (which only generate while the sun is shining). The solar resources support the system during daytime and help to reduce LOLH but are unable to contribute to reducing LOLH at night – this can only be accomplished by the BESS. As a result, there is a higher reduction in LOLH than LOLE.

Table A-30: Calculated Resource Adequacy Risk Measures – Solar PV + BESS Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System + 420 MW Solar PV + 100 MW Solar-Paired BESS (4 Hour Duration)	5.01 Days / Year	20.22 Hours / Year
Current System + 845 MW Solar PV + 200 MW Solar-Paired BESS (4 Hour Duration)	3.12 Days / Year	12.40 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The figure below shows the average LOLH averaged over the 2,000 simulations performed. As shown, the combination of solar PV and BESS nearly eliminates LOLH during the daytime while the sun is shining and also reduces LOLH during the nighttime during BESS injection. Note that there are diminishing returns for doubling the size of the additional generation resources. This is expected given that resource adequacy improvements per MWs added of similar generation types reduce with subsequent additions.

Figure A-59: Comparison of Loss of Load Hours by Hour – Solar PV + BESS Addition



Appendix 26. Sensitivity Analysis – Additional Flexible Thermal Resource

An additional sensitivity analysis was performed to investigate the resource adequacy impact of adding flexible thermal generators to the system. Some examples of flexible thermal generators include reciprocating engines (RICE) or single-cycle combustion turbines (SCCTs). Today, these types of generators are capable of consuming a variety of different types of fuels, including natural gas, various liquid fuels, biofuels, etc. For this analysis, the specific type of fuel that the flexible thermal generator would consume was not a required input.

Two scenarios, in which the current system added both 100 MW and 200 MW of flexible thermal resources, were evaluated to assess resource adequacy improvement. The additional thermal resources modeled were assumed to have a 2% forced outage rate and a two-week planned maintenance event (assumed to occur at the beginning of February 2023). As illustrated in the following table, the first 100 MW of flexible thermal resources added to the current system decreased LOLE from 8.81 days/year to 5.15 days/year, which is a 41% reduction. The second 100 MWs of flexible thermal resources further reduced the LOLE to 3.01 days/year, which is a reduction of 65% from the current system.

The addition of the flexible thermal resources has nearly equal impacts to both LOLE and LOLH. The first 100 MW of flexible thermal resources added to the system decreased the LOLH from 40.77 hours/year to 22.56 hours/year, which is a reduction of 44%. The second 100 MW added to the system further decreased the LOLH to 12.55 hours/year, which is a reduction of 69% from the current system.

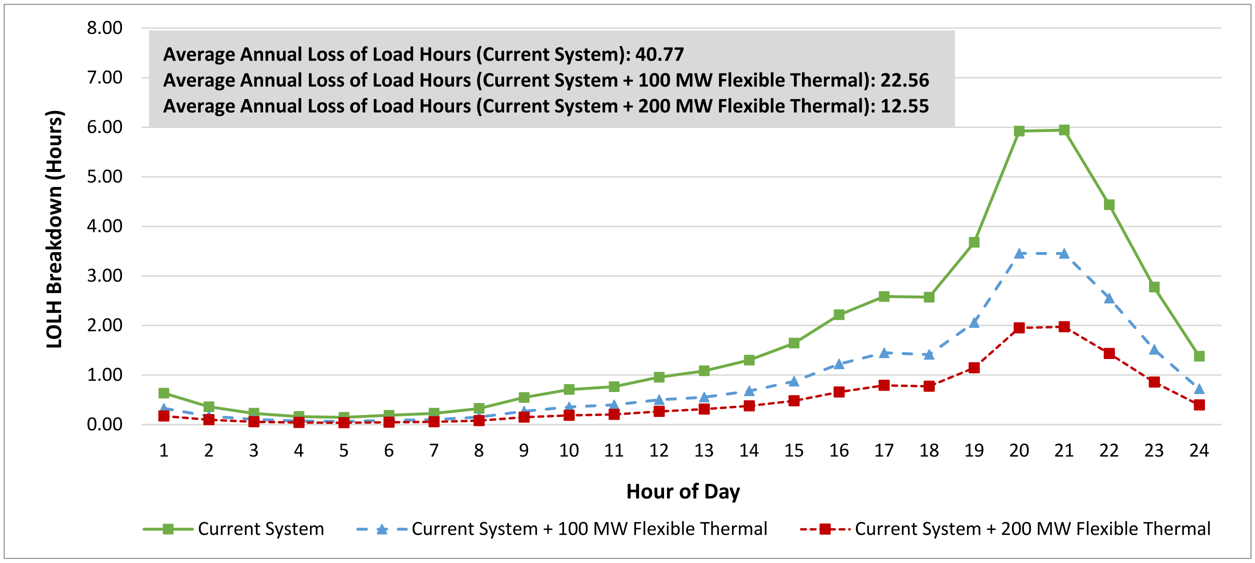
Table A-31: Calculated Resource Adequacy Risk Measures – Flexible Thermal Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System + 100 MW Flexible Thermal Resource	5.15 Days / Year	22.56 Hours / Year
Current System + 200 MW Flexible Thermal Resource	3.01 Days / Year	12.55 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

The following figure provides the average annual loss of load hours for each hour of the day for the current system compared to the two flexible thermal resource scenarios. The figure illustrates two important points. First, the addition of the flexible thermal resources helps to improve system resource adequacy across all hours, including the evening, when the improvements are needed most. The reason for this is because these generators are dispatchable, meaning they can be called to generate virtually any time they are needed, provided they are not on forced / planned maintenance and have sufficient fuel available to operate. Additionally, the addition of the first 100 MW results in greater improvements to both LOLE and LOLH than the second 100 MW, indicating some diminishing returns to resource adequacy improvement. While there are diminishing returns to adding the second 100 MW, the results still indicate

substantial improvements to system resource adequacy for both the addition of 100 MW and 200 MW of flexible thermal generators to the current system.

Figure A-60: Comparison of Loss of Load Hours by Hour – Flexible Thermal Addition



Appendix 27. Sensitivity Analysis – Additional Demand Response Resources

A sensitivity analysis was performed to investigate the resource adequacy impact of adding demand response (DR) resources to the system. DR resources contribute to improving system resource adequacy by reducing load during times of need. For the purposes of reducing system LOLE and LOLH, load reduction is both an efficient and effective alternative to adding new generators. Note that this analysis did not evaluate the costs or potential economic advantages of DR. A detailed analysis of DR as a demand-side resource would be part of a larger IRP process.

The DR resources are modeled in two different sizes: 25 MW and 50 MW. DR resources function as a short-term reduction in system load when requested by the system operator. Given that a DR resource would not be continuously available for every hour of the year, DR is modeled as being available for a limited number of hours in a rolling 24-hour period. The model treats DR as available to be utilized up to a maximum of 8 hours in a rolling 24-hour period. Note that this assumption is considered as an approximation of DR availability – the actual amount a DR resource would be available would depend on the resource and associated agreement in place with the entity that would be reducing load in response to system operator requests.

In the model, the DR resource is only considered as being available after first considering the available capacity of all other generators in the system. In other words, the model considers DR as the last resort option in circumstances where there would otherwise be a generation capacity shortfall. Modeling DR in this manner allows the model to identify how frequently DR is utilized so that it is not used more than allowed (i.e., more than 8 hours in a rolling 24-hour time period). Actual operation of a DR resource in Puerto Rico might be different than the model depending on the capabilities of the DR resource to reduce electrical consumption, cost of the DR resource, specifics of the agreement, among other items.

The LOLE and LOLH results of the sensitivity analysis are provided in the following table. The addition of DR to the system results in a noteworthy improvement both in terms of LOLE and LOLH.

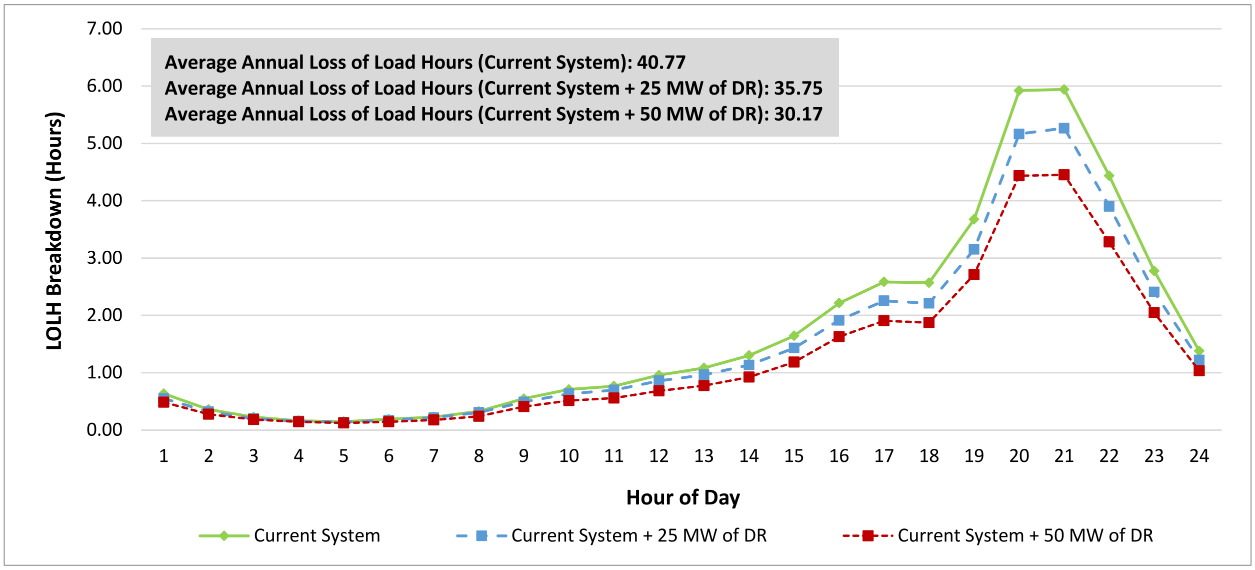
Table A-32: Calculated Resource Adequacy Risk Measures – Demand Response Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
Current System + 25 MW of DR	7.77 Days / Year	35.75 Hours / Year
Current System + 50 MW of DR	6.62 Days / Year	30.17 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

While there is not enough DR available on the island to achieve the 0.1 days per year industry benchmark LOLE target with DR alone, the LOLE and LOLH reductions seen in the simulations after DR was added are significant. The utilization of the DR resources in the model are primarily during the evening time periods, when system load is highest. Model results illustrate that 50 MW of DR has the potential to reduce LOLE by 2.19 days per year (or 25%), while also reducing LOLH by 10.6 hours per year (or 26%).

The following figure provides the average annual loss of load hours for each hour of the day for the current system compared to the two DR scenarios. Over 90% of DR utilization takes place between 1 p.m. and midnight, with 55% of DR utilization taking place from 7 p.m. to 10 p.m. It should be noted that the model only considers DR utilization for the purposes of resource adequacy. Any potential deployment of future DR to reduce generation costs is not captured in the model.

Figure A-61: Comparison of Loss of Load Hours by Hour – Demand Response Addition



Overall, the calculated resource adequacy improvement as a result of adding DR resources make a compelling case for future implementation. DR also has the added benefit of requiring little to no initial investment needed for deployment, especially when compared to constructing traditional generation technologies. DR integration is most effective at improving system resource adequacy in Puerto Rico when it can be deployed during peak hours. To successfully implement DR, coordinated programs would be required to ensure entities are both willing and able to reduce electrical consumption during these times. For this reason, the total amount of available DR that could be successfully implemented is limited. This analysis examines the additions of 25 MW and 50 MW of DR in Puerto Rico, based on an initial estimation of potential opportunities; however, greater than 50 MW could potentially be available if there were sufficient economic incentives.

Appendix 28. Sensitivity Analysis – Load Reduction via Energy Efficiency

A sensitivity analysis was performed to investigate the resource adequacy impact of load reduction as a result of energy efficiency measures. Two different energy efficiency load reductions were modeled: 0.25% and 0.50%. Both energy efficiency load reductions were modeled as consistent percentage reductions from load for each hour of the day. The total annual load reductions equaled 48.4 GWh and 96.7 GWh for the 0.25% and 0.50% scenarios, respectively.

The LOLE and LOLH results of the sensitivity analysis are provided in the following table. As can be seen, reductions in system load as a result of energy efficiency result in modest improvements in system resource adequacy.

Table A-33: Calculated Resource Adequacy Risk Measures – Energy Efficiency Addition

Scenario	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Current System	8.81 Days / Year	40.77 Hours / Year
0.25% Energy Efficiency Hourly Load Reduction	8.56 Days / Year	39.77 Hours / Year
0.50% Energy Efficiency Hourly Load Reduction	8.16 Days / Year	37.36 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

Appendix 29. Forecasted System Dispatch and Generator Cycling

Prior analysis related to the integration of solar PV plus paired energy storage resources has been performed to investigate their impact on overall system generator dispatch (the analysis was performed in early 2022). The analysis utilized the PROMOD production cost simulation tool and simulated the dispatch of Puerto Rico's generators both with and without the Tranche 1 projects. In the analysis, solar PV and energy storage projects were treated as 'must run' (by setting their marginal production costs to zero) so that the solar PV and energy storage would be dispatched fully.

The following two figures compare 1) an annual simulation of the current system to 2) an annual simulation of the current system with the Tranche 1 renewable and storage projects operating (totaling 844.5 MW of solar PV and 220 MW of 4-hour energy storage). The figures compare average hourly dispatch of Puerto Rico's generators, averaged over each day of the simulated year. Generation is broken down by fuel type. For example, generation from the power plants in Puerto Rico that consume natural gas (EcoEléctrica, Costa Sur Units 5 & 6, and San Juan Units 5 & 6) are represented in blue.

As can be observed by comparing the two figures, the addition of Tranche 1 results in a significant amount of renewable generation during the middle of the day. In order for the system to make room for this generation, the operating thermal power plants on the island are required to turn down during the middle of the day. The generators that are primarily able to do so are the generators that consume natural gas. Generators that consume bunker fuel cannot be turned down much further since they are already near or at their minimum stable operating levels, while the generators that consume coal are the lowest cost generators in Puerto Rico and thus are not turned down much for economic reasons. Since the thermal generators are needed to meet load during the evening (when solar generation falls to zero), the thermal generators cannot be turned off during the middle of the day because most would not be able to start back up in time to meet the evening peak load.

Figure A-62: Average Generator Dispatch in the Current System

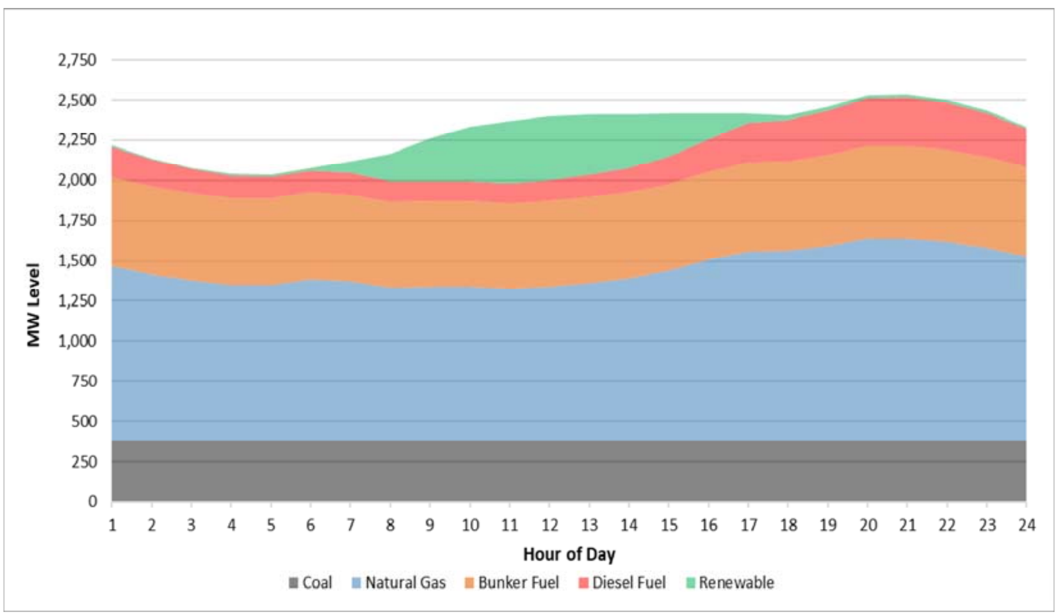
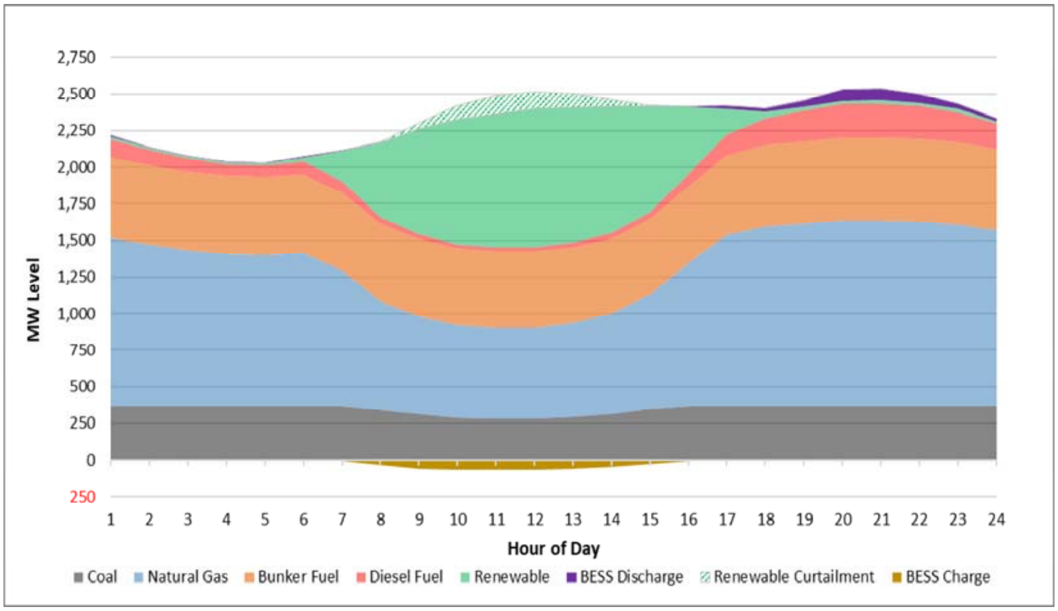


Figure A-63: Forecasted Average Generator Dispatch in the Current System + Tranche 1 Projects



For reference, the small amount of forecasted solar curtailment is because there are times when the thermal generators are all at their minimum operating points, energy storage is fully charging, and there still is some excess solar energy beyond system load that cannot be utilized. The additional tranches of renewable generation are expected to result in higher levels of renewable curtailment.

The addition of Tranche 1 results in a need for the existing thermal generators in Puerto Rico to significantly reduce generation during the middle of the day, then quickly increase generation for the evening; this is also known as generator cycling. One consequence of increased cycling is additional wear on generator equipment, which results in more frequent planned outages and potentially a higher risk of forced outages. From a resource adequacy perspective, while modelling the addition of solar plus paired energy storage to the current system was found to greatly improve system resource adequacy, the impact of thermal generator cycling on planned outage frequency and forced outage rate was not considered in the resource adequacy analysis. An increase in thermal generator planned outage frequency or forced outage rates will have a marginally negative impact on system resource adequacy.